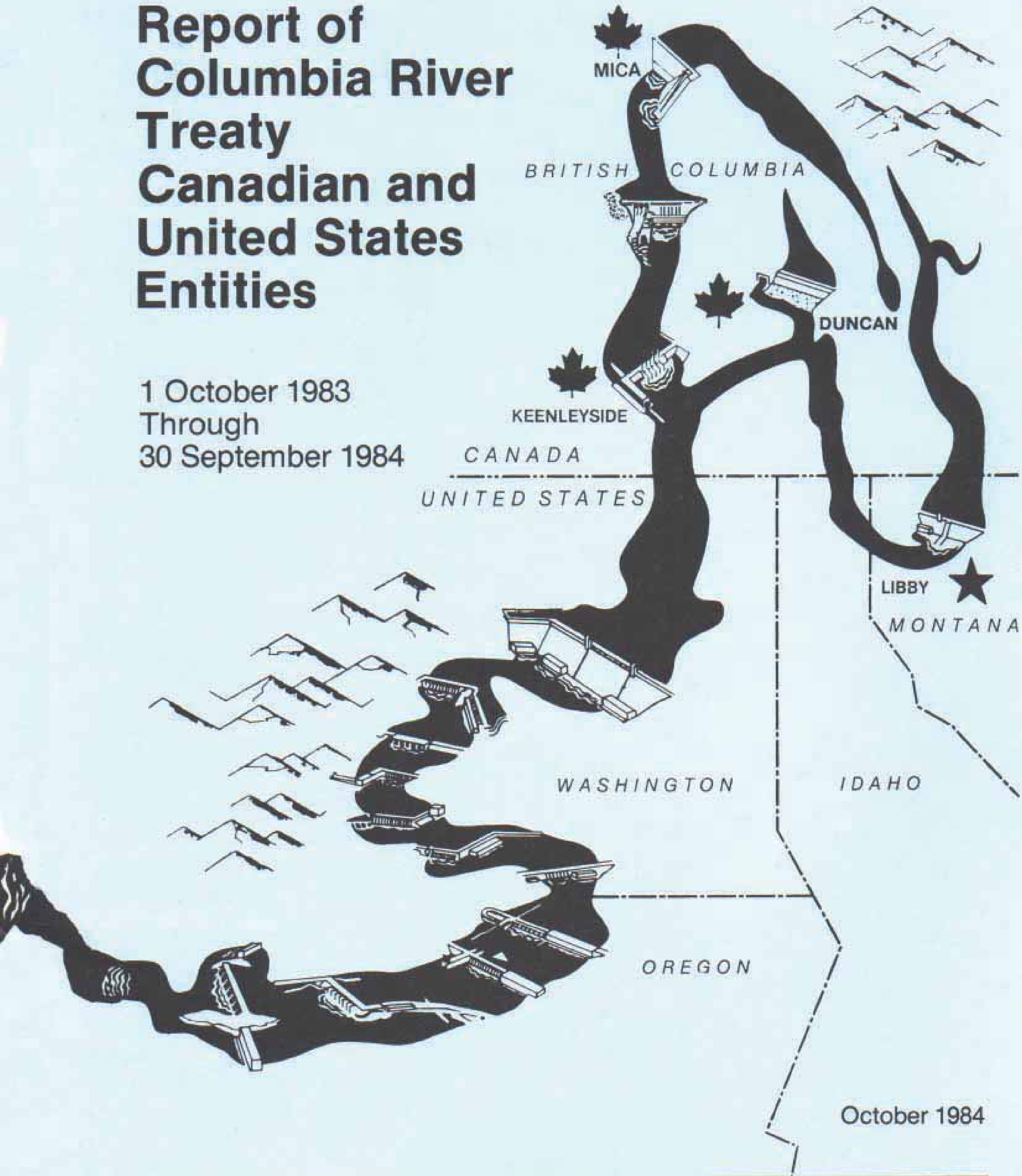
Twentieth Anniversary 1964-1984

Report of Columbia River Treaty Canadian and United States Entities

1 October 1983
Through
30 September 1984



October 1984

ANNUAL REPORT OF THE

COLUMBIA RIVER TREATY

CANADIAN AND UNITED STATES ENTITIES

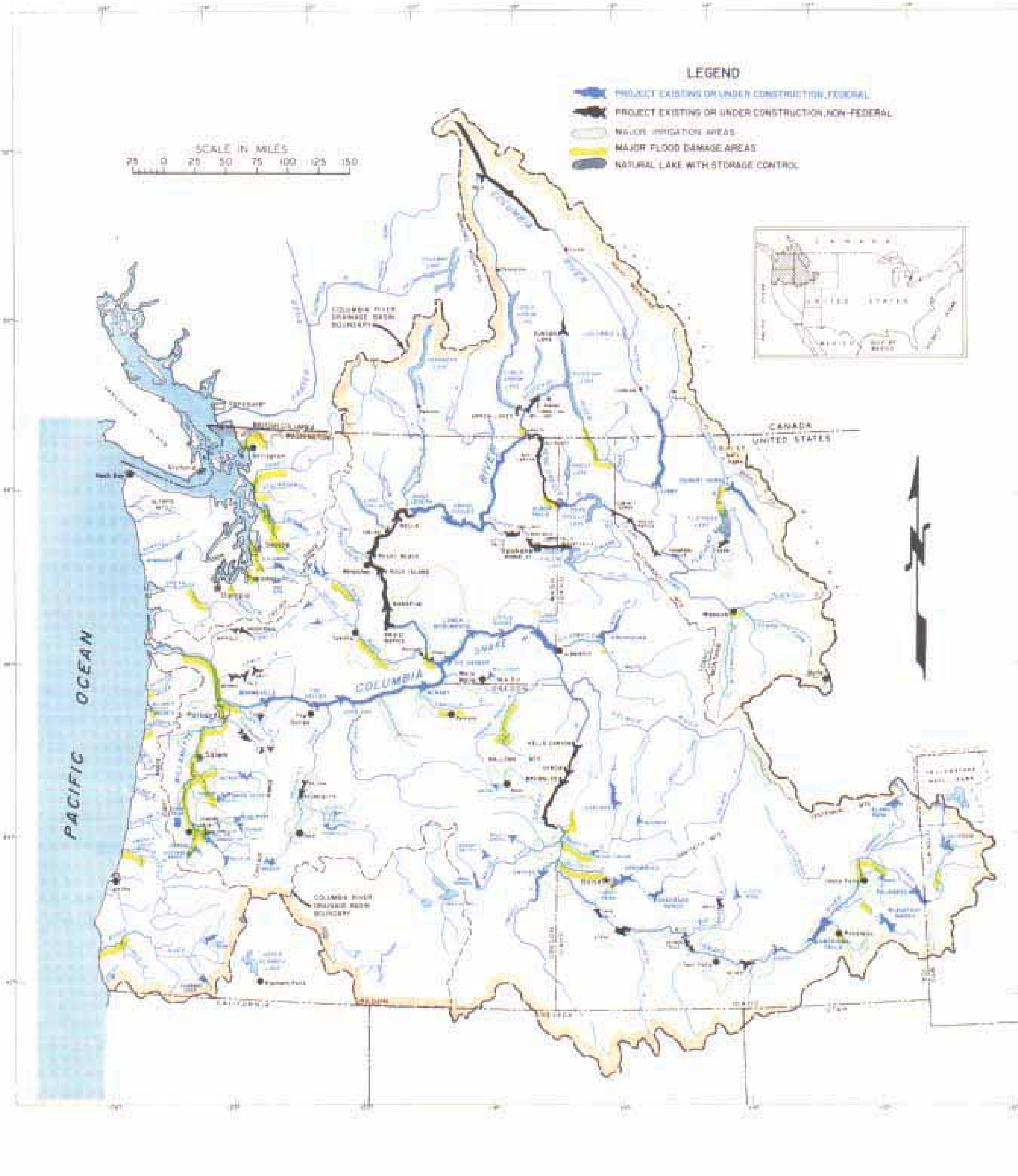
For the Period

1 October 1983

Through

30 September 1984

COLUMBIA RIVER AND COASTAL BASINS



1984 REPORT OF THE COLUMBIA RIVER TREATY ENTITIES

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TWENTIETH ANNIVERSARY 1964-1984

16 September 1984 was the twentieth anniversary of the ratification of the Columbia River Treaty. The Treaty and Protocol were formally ratified on that date by an exchange of notes in Ottawa between the two governments. On that same day in New York City the sum of $253.9-million (U.S.) was delivered to Canadian representatives as payment in advance for the Canadian entitlement to downstream power benefits during the period of the Purchase Agreement. On the same date at a ceremony at the Peace Arch Park on the International Boundary, the Treaty and its Protocol were proclaimed by President Johnson, Prime Minister Pearson, and Premier Bennett of British Columbia. U.S. payments to Canada totalling $64.4-million (U.S.) for flood control benefits were made later on the commencement of respective storage operations.

16 September 1964 marked the culmination of work that began in 1944 when the governments of Canada and the United States asked the International Joint Commission to conduct an inquiry into "whether a greater use than is now being made of the waters of the Columbia River System would be feasible and advantageous". The IJC's report to the governments was submitted in 1959 and it recommended project development and methods for distributing the benefits. These and other activities led to the Columbia River Treaty.

The Treaty was signed in Washington, D.C. on 17 January 1961 and was ratified by the United States Senate in March of that year. In Canada ratification was delayed. Further negotiations between the two countries resulted in formal agreement by an exchange of notes on 22 January 1964 to a Protocol to the Treaty and to an Attachment Relating to Terms of Sale. The Treaty and related documents were approved by the Canadian Parliament in June 1964.

The Canadian Entitlement Purchase Agreement was signed on 13 August 1964. Under the terms of this agreement Canada's share of downstream power benefits resulting from the first thirty years of scheduled operation of each of the storage projects was sold to a group of electric utilities in the United States known as the Columbia Storage Power Exchange. The Canadian Entitlement Purchase Agreement of 13 August 1964 provided that the Treaty storages would be operative for power purposes beginning 1 April 1968 for Duncan storage, 1 April 1969 for Arrow storage and 1 April 1973 for Mica storage.

On 15 September 1964, the Pacific Northwest Coordination Agreement was brought into effect as a new foundation for Pacific Northwest hydropower planning and operating procedures. The Coordination Agreement was needed to assure the coordinated operation of U.S. reservoirs in order to guarantee the production of Treaty downstream power benefits. Because the Treaty power benefits were not immediately needed in the Pacific Northwest, the U.S. Congress had authorized in August 1964, the construction of an intertie to California that has benefited both the U.S. Pacific Northwest and British Columbia.

The Libby reservoir began operation in March 1972. Treaty storage made powerhouse enlargement economical for hydropower projects downstream in the U.S. British Columbia has been able to construct hydropower projects that benefit from the operation of Treaty reservoirs. B.C. Hydro has installed generating facilities at Mica Dam, and has constructed Revelstoke and Kootenay Canal Plant projects downstream from Treaty reservoirs. These projects have benefit to cost ratios far above alternatives available without the Treaty reservoirs.

These twenty years of Treaty experience between 1964 and 1984 have demonstrated how the good will and effort of the U.S. and Canadian people have successfully harnessed a shared natural resource for the benefit of both. The Entities look forward to future cooperation and mutual benefits.

1984 REPORT OF THE COLUMBIA RIVER TREATY ENTITIES

I. INTRODUCTION

This annual Columbia River Treaty Entity report is for the water year, 1 October 1983 through 30 September 1984. It includes information on the operation of Mica, Arrow, Duncan and Libby reservoirs during that period with additional information covering the reservoir system operating year, 1 August 1983 through 31 July 1984. The power and flood control effects downstream in Canada and the United States are described. This report is the eighteenth of a series of annual reports covering the period since the ratification of the Columbia River Treaty, in September 1964. The first report in this series was dated 22 April 1968 and covered the period 16 September 1964 to 30 September 1967.

Duncan, Arrow, and Mica reservoirs in Canada and Libby reservoir in the United States of America were constructed under the provisions of the Columbia River Treaty of January 1961. Treaty storage in Canada is required to be operated for the purposes of increasing hydroelectric power generation, and for flood control in the United States of America and in Canada. In 1964, the Canadian and United States governments each designated an Entity to formulate and carry out the operating arrangements necessary to implement the Treaty. The Canadian Entity is British Columbia Hydro and Power Authority (B.C. Hydro). The United States Entity is the Administrator of the Bonneville Power Administration (BPA) and the Division Engineer of the North Pacific Division, Army Corps of Engineers (ACE).

The following is a summary of key features of the Treaty and related documents:

1. Canada is to provide 15.5 million acre-feet (maf) of usable storage. (This has been accomplished with 7.0 maf in Mica, 7.1 maf in Arrow and 1.4 maf in Duncan).

2. For the purpose of computing downstream benefits the U.S. hydroelectric facilities will be operated in a manner that makes the most effective use of the improved streamflow resulting from operation of the Canadian storage.

3. The U.S. and Canada are to share equally the additional power generated in the U.S. resulting from operation of the Canadian storage.

4. The U.S. paid Canada a lump sum of $64.4-million (U.S.) for expected flood control benefits in the U.S. resulting from operation of the Canadian storage.

5. The U.S. has the option of requesting the evacuation of additional flood control space above that specified in the Treaty, for a payment of $1.875-million (U.S.) for each of the first four requests for this "on-call" storage.

6. The U.S. constructed Libby Dam with a reservoir that extends 42 miles into Canada and for which Canada made the land available.

7. Both Canada and the United States have the right to make diversions of water for consumptive uses and, in addition, after September 1984 Canada has the option of making for power purposes specific diversions of the Kootenay River into the headwaters of the Columbia River.

8. Differences arising under the Treaty which cannot be resolved by the two countries may be referred by either to the International Joint Commission (IJC) or to arbitration by an appropriate tribunal.

9. The Treaty shall remain in force for at least 60 years from its date of ratification, 16 September 1964.

10. In the Canadian Entitlement Purchase Agreement of 13 August 1964, Canada sold its entitlement to downstream power benefits to the United States for 30-years beginning at Duncan on 1 April 1968, at Arrow on 1 April 1969, and at Mica on 1 April 1973.

11. Canada and the U.S. are each to appoint Entities to implement Treaty provisions and are to jointly appoint a Permanent Engineering Board (PEB) to review and report on operations under the Treaty.

II. TREATY ORGANIZATION

Entities

There was one meeting of the Entities (including the Canadian Entity Representative and U.S. Coordinators) during the year on the morning of 30 November 1983 in Seattle, Washington. The members of the two Entities during the period of this report were:

United States Entity

Mr. Peter T. Johnson, Chairman
Administrator, Bonnneville
Power Administration,
Department of Energy,
Portland, Oregon

Brigadier General George R. Robertson
Division Engineer,
North Pacific Division,
Army Corps of Engineers,
Portland, Oregon

Canadian Entity

Mr. R.W. Bonner, Chairman
Chairman, British Columbia
Hydro and Power Authority,
Vancouver, B.C.

General Robertson succeeded Colonel James H. Higman on 5 September 1984, who in turn had succeeded General James W. van Loben Sels on 22 June 1984.

The Entities have appointed Coordinators and a Representative and two joint standing committees to assist in Treaty implementation activities. These are described in subsequent paragraphs. The primary duties and responsibilities of the Entities as specified in the Treaty and related documents are:

1. Plan and exchange information relating to facilities used to obtain the benefits contemplated by the Treaty.

2. Calculate and arrange for delivery of hydroelectric power to which Canada is entitled and the amounts payable to the U.S. for standby transmission services.

3. Operate a hydrometeorological system.

4. Assist and cooperate with the Permanent Engineering Board in the discharge of its functions.

5. Prepare hydroelectric and flood control operating plans for the use of Canadian storage.

6. Prepare and implement detailed operating plans that may produce results more advantageous to both countries than those that would arise from operation under assured operating plans.

7. The Treaty provides that the two governments may, by an exchange of notes, empower or charge the Entities with any other matter coming within the scope of the Treaty.

Entity Coordinators and Representative

The Entities have appointed members of their respective staffs to serve as coordinators or focal points on Treaty matters within their organizations. These are:

United States Entity Coordinators

Edward W. Sienkiewicz, Coordinator
Asst. Administrator for Power & Resources Management
Bonneville Power Administration
Portland, Oregon

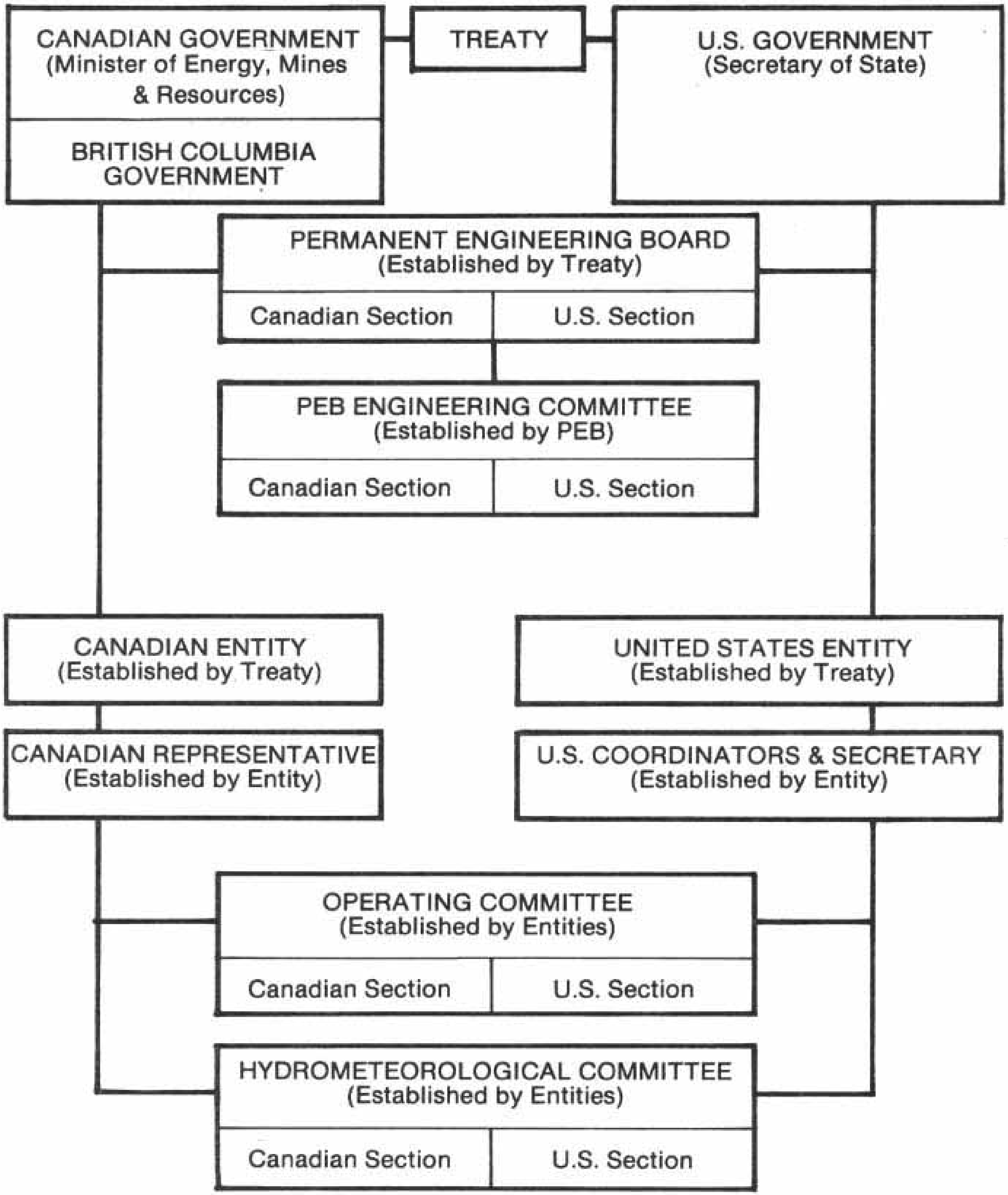
Herbert H. Kennon, Coordinator
Chief, Engineering Division
North Pacific Division
Army Corps of Engineers
Portland, Oregon

John M. Hyde, Secretary
Bonneville Power Administration
Portland, Oregon

Canadian Entity Representative

Douglas R. Forrest, Manager
Canadian Entity Services
B.C. Hydro & Power Authority
Vancouver, B.C.

COLUMBIA RIVER TREATY ORGANIZATION



Entity Operating Committee

The Operating Committee was established in September 1968 by the Entities and is responsible for preparing and implementing operating plans as required by the Columbia River Treaty, making studies and otherwise assisting the Entities as needed. The Operating Committee consists of eight members as follows:

United States Section	Canadian Section
Lawrence A. Dean, BPA, Co-Chairman	Timothy J. Newton, Chairman
Nicholas A. Dodge, ACE, Co-Chairman	Ralph D. Legge
Gordon G. Green, ACE	William N. Tivy
John M. Hyde, BPA	Kenneth R. Spafford

There were six meetings of the Operating Committee during the year, including tours of the Revelstoke and Libby projects. The dates, places and number of persons attending those meetings were:

6 October 1983 at Revelstoke Project, B.C., with 17 attendees;
5 December 1983 at Portland, Oregon, with 15 attendees;
14 February 1984 at Vancouver, B.C., with 18 attendees;
18 April 1984 at Portland, Oregon, with 18 attendees;
14 June 1984 at Vancouver, B.C., with 16 attendees; and
14 August 1984 at Libby, Montana, with 21 attendees (including 2 from West Kootenay Power and Light and 2 from the Libby project).

The Operating Committee coordinated the operation of the Treaty storage in accordance with the current hydroelectric and flood control operating plans. This aspect of the Committee's work is described in following sections of this report which has been prepared by the Committee with the assistance of others.

The Committee prepared the Entity agreements listed in the following section and developed operating plans and downstream benefit determinations for subsequent operating years. The Committee monitored the implementation of the long term non-Treaty storage agreement, signed by the Entities in April 1984, to assure that it was consistent with the Operating Plans.

The Committee completed an analysis of the impact on Treaty operating plans and downstream benefits due to the inclusion of the Northwest Power Planning Council's Fish and Wildlife Program water budget flows in the Assured Operating Plan and the Determination of Downstream Power Benefits. The Committee also analyzed the impact of using updated streamflow records in the Determination of Downstream Power Benefits.

Entity Hydrometeorological Committee

The Hydrometeorological Committee was established in September 1968 by the Entities and is responsible for planning and monitoring the operation of data facilities in accord with the Treaty and otherwise assisting the Entities as needed. The Committee consists of four members as follows:

United States Section	**Canadian Section**
Douglas D. Speers ACE, Co-Chairman	Ulrich Sporns, Chairman
Roger G. Hearn, BPA, Co-Chairman	John R. Gordon

The Hydrometeorological Committee met once during the year on 2 May 1984 in Portland, Oregon with 12 persons in attendance. The topics covered at the meeting were:

1. Finalizing the draft Hydrometeorological Committee Document that was issued in the fall of 1983.

2. Discussion of the volume forecasting routines using the 20-year (1961-1980) record as a reference period.

3. Discussion of data exchange problems and the conversion to automatic transfer of data from B.C. Hydro to ACE and BPA.

Work proceeded on converting Canadian hydromet stations to remote Data Collection Platforms (DCP). Data are being collected by satellite and transferred via the BPA/BCH microwave channel to the Columbia River Operational Hydromet Management System (CROHMS) computer in the ACE office in Portland. Actual automated hourly transmissions of Canadian real-time hydromet data into CROHMS were started on 15 August 1984. These data are being rebroadcast over the Columbia Basin Telecommunications (CBT) network to other interested parties. B.C. Hydro operated a terminal in the CBT network (formerly Columbia Basin Teletype - CBTT) until last year. Since that time data transfer has been accomplished by direct computer transmissions through CROHMS facilities.

The Committee expects to issue the "Columbia River Treaty Hydrometeorological Committee Document" in final form before the end of 1984. It was agreed to list both the Treaty and the Treaty Support facilities together noting on the listing which type of facility it is.

The 20-year reference period (1961-1980) was used operationally for the first time in 1984 including some comparisons in this report, and is expected to be used as the primary basis for comparisons in next year's annual Treaty report. The previous 15-year reference period (1963-1977) is still used for a few comparisons in this report.

Permanent Engineering Board

Provisions for the establishment of the Permanent Engineering Board (PEB) and its duties and responsibilities are included in the Treaty and related documents. The members of the PEB are presently:

United States Section	Canadian Section
Lloyd A. Duscha, Chairman Washington, D.C.	G.M. McNabb, Chairman Ottawa,Ontario
J. Emerson Harper, Member Washington, D.C.	B.E. Marr, Member Victoria, B.C.
Alex Shwaiko, Alternate Washington, D.C	H.M. Hunt, Alternate Victoria, B.C.
Thomas L. Weaver, Alternate Golden, Colorado	E.M. Clark, Alternate and Secretary Vancouver, B.C.
S.A. Zanganeh, Secretary Washington, D.C.	

In general the duties and responsibilities of the PEB are to assemble records of flows of the Columbia River and the Kootenay River at the international boundary; report to both governments if there is deviation from the hydroelectric and flood control operating plans and if appropriate include recommendations for remedial action; assist in reconciling differences that may arise between the Entities; make periodic inspections and obtain reports as needed from the Entities to assure that Treaty objectives are being met; make an annual report to both governments and special reports when appropriate; consult with the Entities in the establishment and operation of a hydrometeorological system; and, investigate and report on any other Treaty related matter at the request of either government.

The Entities continued their cooperation with the PEB during the past year by providing copies of Entity agreements, operating plans, downstream benefit computations, hydrometeorological documents, and the annual Entity report to the Board for their review. The annual joint meeting of the Permanent Engineering Board and the Entities was held on the afternoon of 30 November 1983 in Seattle, Washington.

PEB Engineering Committee

The PEB has established a PEB Engineering Committee (PEBCOM) to assist in carrying out its duties. The members of PEBCOM are presently:

United States Section

Vernon K. Hagen, Chairman
Washington, D.C.
Gary L. Fuqua, Member
Portland, Oregon
Larry Larson, Alternate
Washington, D.C
S.A. Zanganeh, Alternate
Washington, D.C.

Canadian Section

Ron White, Chairman
Vancouver, B.C.
David Tanner, Member
Victoria, B.C.

International Joint Commission

The International Joint Commission (IJC) was created under the Boundary Waters Treaty of 1909 between Canada and the U.S. Its principal functions are rendering decisions on the use of boundary waters, investigating important problems arising along the common frontier not necessarily connected with waterways, and making recommendations on any question referred to it by either government. If a dispute concerning the Columbia River Treaty could not be resolved by the Entities or the PEB it

BRITISH COLUMBIA HYDRO AND POWER AUTHORITY. Treaty support staff from left to right, sitting: Ulrich Sporns, Robert W. Bonner, Douglas R. Forrest, and Timothy J. Newton: standing: John R. Gordon, William N. Tivy, Ralph D. Legge, and Kenneth R. Spafford. Shown below is the BC Hydro System Control Centre atop Burnaby Mountain in Burnaby, B.C. The Centre was commissioned on 2 December 1972.

would probably be referred to the IJC for resolution before being submitted to a tribunal for arbitration.

The IJC has appointed local Boards of Control to insure compliance with IJC orders and to keep the IJC currently informed. There are four such boards west of the continental divide. These are the International Kootenay Lake Board of Control, the International Columbia River Board of Control, the International Osoyoos Lake Board of Control and the International Skagit River Board of Control. The Entities and their committees conducted their Treaty activities during the period of this report so that there was no known conflict with IJC orders or rules.

III. OPERATING ARRANGEMENTS

Power and Flood Control Operating Plans

The Columbia River Treaty requires that the reservoirs constructed in Canada be operated pursuant to flood control and hydroelectric operating plans developed thereunder. Annex A of the Treaty stipulates that the United States Entity will submit flood control operating plans and that the Canadian Entity will operate in accordance with flood control storage diagrams or any variation which the Entities agree will not be adverse to the desired aim of the flood control plan. Annex A also provides for the development of hydroelectric operating plans five years in advance to furnish the Entities with an Assured Operating Plan for Canadian storage. In addition, Article XIV.2.k of the Treaty provides that a Detailed Operating Plan may be developed to produce more advantageous results through use of current estimates of loads and resources. The Protocol to the Treaty provides further detail and clarification of the principles and requirements of Annex A.

The "Principles and Procedures for the Preparation and Use of Hydroelectric Operating Plans" dated May 1983 together with the "Columbia River Treaty Flood Control Operating Plan" dated October 1972, establish and explain the general criteria used to plan and operate Treaty storage during the period covered by this report. These documents were previously approved by the Entities. Most of the planning and operation of the coordinated reservoir system in the Pacific Northwest, including Treaty storage, is done for the operating year, 1 August through 31 July.

Assured Operating Plan

The Assured Operating Plan (AOP) dated September 1978 established Operating Rule Curves for Duncan, Arrow and Mica during the 1983-84 operating year. The Operating Rule Curves provided guidelines for refill levels as well as drawdown levels. They were derived from Critical Rule Curves, Assured Refill Curves, Upper Rule Curves, and Variable Refill Curves, consistent with flood control requirements, as described in the 1983 Principles and Procedures document. The Flood Control Storage Reservation Curves were established to conform to the Flood Control Operating Plan of 1972. The AOP for operating year 1988-89 was prepared during the year covered by this report for future use.

Detailed Operating Plan

During the period covered by this report, storage operations were implemented by the Operating Committee in accordance with the "Detailed Operating Plan for Columbia River Treaty Storage" (DOP), dated September 1983. The DOP established criteria for determining the Operating Rule Curves for use in actual operations. Except for a minor change at Arrow, the DOP used the AOP critical rule curves for Canadian projects. The Canadian Entity agreed to raise the Arrow first year February and April critical rule curve to improve the hydro-regulation in the 1983-84 Pacific Northwest Coordination Agreement operating plans. The Variable Refill Curves and flood control requirements subsequent to 1 January 1984 were determined on the basis of seasonal volume runoff forecasts during actual operation. The regulation of the Canadian storage was conducted by the Operating Committee on a weekly basis except when flood control operation required daily regulation. During the period of this report the DOP for operating year 1984-85 was prepared.

Determination of Downstream Power Benefits

For each operating year, the determination of downstream power benefits is made five years in advance in conjunction with the Assured Operating Plan. For operating years 1982-83 and 1983-84, the estimates of benefits resulting from operating plans designed to achieve optimum operation in both countries were less than that which would have prevailed from an optimum operation in the United States only. Therefore, in accordance with Sections 7 and 10 of the Canadian Entitlement Purchase Agreement, the Entities agreed that the United States was entitled to receive 5 average megawatts of energy during the period 1 August 1983 through 31 March 1984, and 5.5 average megawatts of energy during the period from 1 April through 31 July 1984. Suitable arrangements were made between the Bonneville Power Administration and B.C. Hydro for delivery of this energy. Computations indicated no loss or gain in dependable capacity during the 1983-84 operating year.

Non-Treaty Storage Agreement

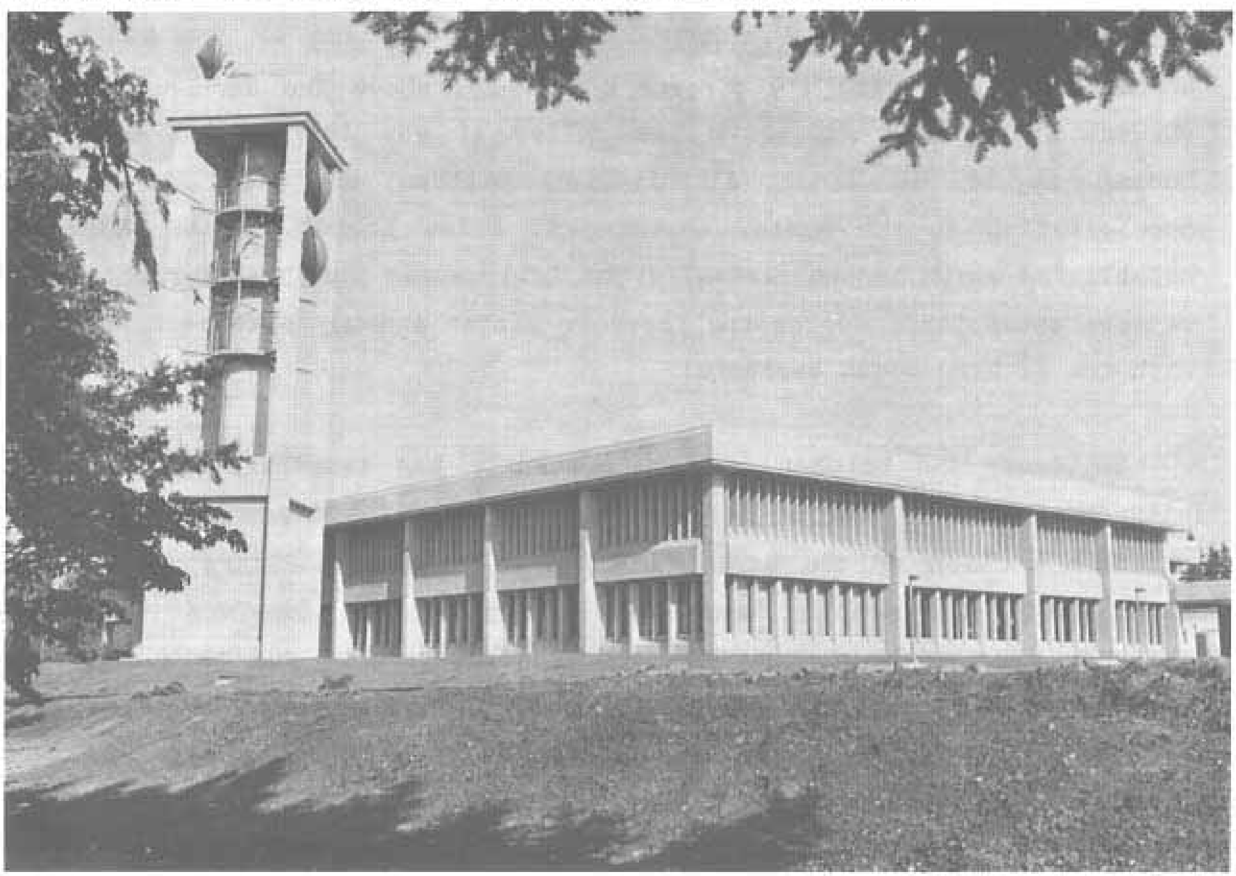
An Entity agreement was completed on 9 April 1984 indicating their approval of a new long term contract between B.C. Hydro and BPA (BPA contract no. DE-MS79-84BP90946) relating to the initial filling of Revelstoke and the coordinated use of some of the Canadian Columbia River non-Treaty storage, and also approval of a companion contract between BPA and mid-Columbia purchasers (BPA contract no. DE-MS79-84BP90945) providing for a coordinated implementation in the U.S. of the contract between BPA and B.C. Hydro. These storage contracts are expected to be in force for 10 years from the effective date of 1 October 1983 and involve a total of 2.0 maf of non-Treaty Active storage space and 2.3 maf of non-Treaty Inactive storage space (Revelstoke). This 9 April 1984 Entity agreement states in part: "The United States and Canadian Entities have reviewed these agreements and are satisfied that there are mutual benefits to be derived from these agreements and that these benefits can be achieved without adversely affecting: (1) the operation of Treaty space in accordance with the Columbia River Treaty; and (2) the performance of obligations pursuant to the Canadian Entitlement Purchase Agreement. The Columbia River Treaty Operating Committee is hereby instructed to insure that any operation pursuant to these agreements does not adversely affect operation of Treaty space pursuant to the Columbia River Treaty."

Entity Agreements

During the period covered by this report four new agreements were officially approved by the Entities. The following tabulation indicates the date each of these were signed or approved and gives a description of the official title of the agreement:

Date Agreement Signed by Entities	Description
30 November 1983	Columbia River Treaty Hydroelectric Operating Plan - Assured Operating Plan for Operating Year 1988-89, dated October 1983
30 November 1983	Determination of Downstream Power Benefits resulting from Canadian Storage for Operating Year 1988-89, dated October 1983
30 November 1983	Detailed Operating Plan for Columbia River Treaty Storage, 1 August 1983 through 31 July 1984, dated September 1983
9 April 1984	Entity approval of the agreement relating to the initial filling of non-Treaty reservoirs, the use of Columbia River non-Treaty storage, and Mica and Arrow reservoir refill enhancement.

BONNEVILLE POWER ADMINISTRATION. Treaty support staff from left to right, sitting: Lawrence A. Dean, Peter T. Johnson, and Edward W. Sienkiewicz; standing; Joseph Volpe, Gary E. Todd, Robert D. Griffin, Roger G. Hearn, John M. Hyde, William R. Gordon and Charles E. Cancilla. Shown below is the BPA Dittmer System Control Center at the Ross Complex in Vancouver, Washington. The Center was energized on 1 December 1974.



IV. 1983-84 WEATHER AND STREAMFLOW

Weather

Indices of temperature and precipitation in the Columbia Basin are shown on charts 2, 3 and 4 for the 1 September 1983 to 31 August 1984 period. Chart 2 also shows an index of the accumulated snowpack in the Columbia Basin above The Dalles in percent of normal for the 1 January through 1 May 1984 period. Chart 1 is a geographical illustration of the seasonal precipitation in percent of normal for the 1 October 1983 through 31 March 1984 period in the Columbia River Basin. The following paragraphs describe significant weather factors from 1 August 1983 to 30 September 1984. In this report temperatures are given in degrees Fahrenheit.

During August 1983 the weather in the Columbia Basin was variable, with mild temperatures generally 2 to $6^{o}F$ above normal, while at the same time precipitation was generally heavy, with that portion of the basin above Grand Coulee receiving 119 percent of normal, above Ice Harbor it was 176 percent of normal, and above The Dalles it was 144 percent of normal. During August an areal distribution pattern of well above normal precipitation in the south, tapering to below normal in the north, was established which lasted virtually the full year. This was a repeat of the pattern established during the previous winter and may have been associated with the El Nino ocean currents.

September and October of 1983 generally had temperatures near normal with precipitation near or below normal. Even so, the precipitation in the southern portion of the basin, i.e., the southern boundary of the Snake River Basin, was greater than that in the north. Snowpack accumulation began in November which had the most precipitation of any month covered by this report. Warm moist air moving over the basin resulted in normal to much above normal precipitation over most of the Columbia Basin. Again the heaviest precipitation was along the southern boundary of Oregon and Idaho. Although the Columbia Basin was unusually cold during December, with some temperatures as much as 32°F below normal, enough moist air infiltrated the Snake River Basin to result in 150 percent of normal precipitation in that area while the basin above Grand Coulee received only 68 percent of normal.

Precipitation in January 1984 was below normal and it reversed its pattern to give 76 percent above Grand Coulee and only 40 percent in the Snake River Basin. In southern Idaho the problem of ice jams, caused by a continuation of the cold weather, and complicated by a sudden warming near month's end, resulted in flooding along the Lemhi, Salmon, and Grande Ronde Rivers. During February, temperatures moderated but precipitation remained below normal over most of the Columbia Basin. March and April saw a return of normal, to much above normal precipitation over most of the Columbia Basin with the heaviest again being along the southern Oregon and Idaho borders.

The 1984 snowmelt season began in mid-April with three very hot days when temperatures climbed to 10 to 20°F above normal. Soon thereafter the temperatures became much cooler and generally remained much below normal until mid June except for two brief warm spells. The spring was unusually cool and wet as indicated by above normal precipitation in May and June, and by the accumulative degree-days which reached a minus 400 by late June. Snowmelt during the two brief hot spells the second and fourth weeks of May was augmented by precipitation that averaged over 140 percent of normal. Above normal precipitation continued through June with only the Flathead and Clark Fork Basins registering less than normal precipitation. Some areas in the Columbia Basin such as the Willamette Valley received such heavy precipitation in June that low level flooding occurred that was unusual for that time of year.

Temperatures during July and August 1984 were generally near or above normal, and dry weather persisted throughout most of the month although moderate to heavy rains fell at the end of August. During September the Pacific Northwest experienced mostly cool showery days. Precipitation for the month was 110 percent of average for the Columbia Basin above Grand Coulee and 97 percent of average above The Dalles. September temperatures averaged near normal west of the Cascades for the third consecutive month, while eastside stations averaged 2 to 4°F below normal.

Streamflow

The observed inflow and outflow hydrographs for the period 1 July 1983 to 31 July 1984 are shown on charts 5 through 8 for the four Treaty reservoirs. Observed flow and the computed unregulated flow hydrographs for the same 13-month period for Kootenay Lake, Columbia River at Birchbank, Grand Coulee and The Dalles are shown on charts 9, 10, 11 and 12 respectively. Chart 13 is a hydrograph of observed and unregulated flows at The Dalles during the April through July 1984 period. Also shown on chart 13 is a hydrograph of flow that would have occurred if regulated only by the Treaty reservoirs. The following paragraphs describe significant streamflow events from the summer of 1983 through September 1984.

Streamflow during the August through October 1983 period reflected the recession from the snowmelt and the unseasonably heavy rains of July. There was greater than normal discharge in the southern half of the basin, while there was normal, to below normal flow in the northern portions. Exceptions to this pattern were in the Okanagan and Kettle Basins in British Columbia which had well above average streamflows. Another exception was the upper Columbia, Kootenay and Flathead Basins which experienced below, to much below normal flows.

During the winter 1983-84 snow accumulation season, November through March, the magnitude of streamflows followed the intensity of monthly precipitation except where regulated by reservoirs. After November, when all rivers experienced much greater than normal discharges, a flow pattern was established that lasted throughout the season. Flows in southern Idaho and eastern Oregon were well above normal, while the northern portions of the basin, with two exceptions, experienced normal, to below normal discharges. These exceptions included the Okanagan and Kettle Basins which continued to have greater than normal discharges. Other exceptions were the Clark Fork, Flathead and Kootenay Basins which generally experienced much below normal discharges. Cold weather during late December and January caused ice jams and some flooding, mainly in the Snake Basin.

Streamflows began to increase due to snowmelt runoff beginning in April 1984 and generally continued to increase until they reached their peaks in late June or early July. The maximum mean monthly modified streamflow for the Columbia River at Grand Coulee occurred as usual in June this year and was 113 percent of the long-term average. The maximum value for the Columbia River at The Dalles also occurred during the usual maximum month of June and was 128 percent of the long-term average. Maximum observed mean daily inflows during the 1983-84 operating year were 114,730 cfs at Mica on 29 June, 101,370 cfs at Arrow on 30 June, 27,040 cfs at Duncan on 29 June and 51,100 cfs at Libby on 17 June. The maximum observed mean daily flow in the Columbia River at The Dalles was 376,000 cfs on 27 June and the peak unregulated flow was 628,000 cfs on 23 June.

The 1983-1984 monthly modified streamflows and the average monthly flows for the 1926-1983 period are shown in the following table for the Columbia River at Grand Coulee and at The Dalles. These modified flows have been corrected for storage in lakes and reservoirs to exclude the effects of regulation, and are adjusted to the 1970 level of development for irrigation.

	Columbia River at Grand Coulee in cfs		Columbia River at at The Dalles in cfs	
Time Period	Year 1983-1984	Average 1926-1983	Year 1983-1984	Average 1926-1983
AUG '83	108,500	97,880	154,400	133,840
SEP	57,700	60,210	92,630	92,580
OCT	41,440	50,910	81,500	88,140
NOV	72,660	46,870	130,000	91,430
DEC	37,180	43,510	94,810	95,520
JAN '84	55,650	38,940	146,300	92,640
FEB	44,900	42,100	120,100	105,410
MAR	66,590	48,970	187,700	120,830
APR	115,100	114,520	268,000	218,190
MAY	174,400	264,810	370,800	416,860
JUN	358,100	315,730	601,800	471,320
JUL	204,900	187,600	297,700	254,400
YEAR	111,540	109,620	212,230	181,990

Seasonal Runoff Volume

In 1984, the runoff volume forecasts, based on precipitation and snowpack data, were prepared as usual for a large number of locations in the Columbia River Basin and updated each month as the season advanced. The 1 April 1984 forecast of January through July runoff of the Columbia River above The Dalles was 102.0 maf and the actual observed runoff was 119.1 maf, a 17 percent differential. Table 1 lists the seasonal volume inflow forecasts for Mica, Arrow, Duncan, and Libby projects and for the unregulated runoff for the Columbia River at The Dalles for the April through August or July period. The forecasts for Mica, Arrow and Duncan inflow were prepared by B.C. Hydro and those for the lower Columbia River and Libby inflows were prepared by the United States Columbia River Forecasting Service. Also shown in table 1 are the actual volumes for these five locations.

Observed 1984 April-August runoff volumes, adjusted to exclude the effects of regulation of upstream storage, are also listed for eight locations in the following tabulation:

Location	Volume in 1000 Acre-Feet	Percent of 1963-77 Average
Libby Reservoir Inflow	5,107	75
Duncan Reservoir Inflow	1,891	90
Mica Reservoir Inflow	10,012	84
Arrow Reservoir Inflow	21,126	89
Columbia River at Birchbank	36,691	87
Grand Coulee Reservoir Inflow	59,275	93
Snake River at Lower Granite Dam	34,382	140
Columbia River at The Dalles	102,231	105

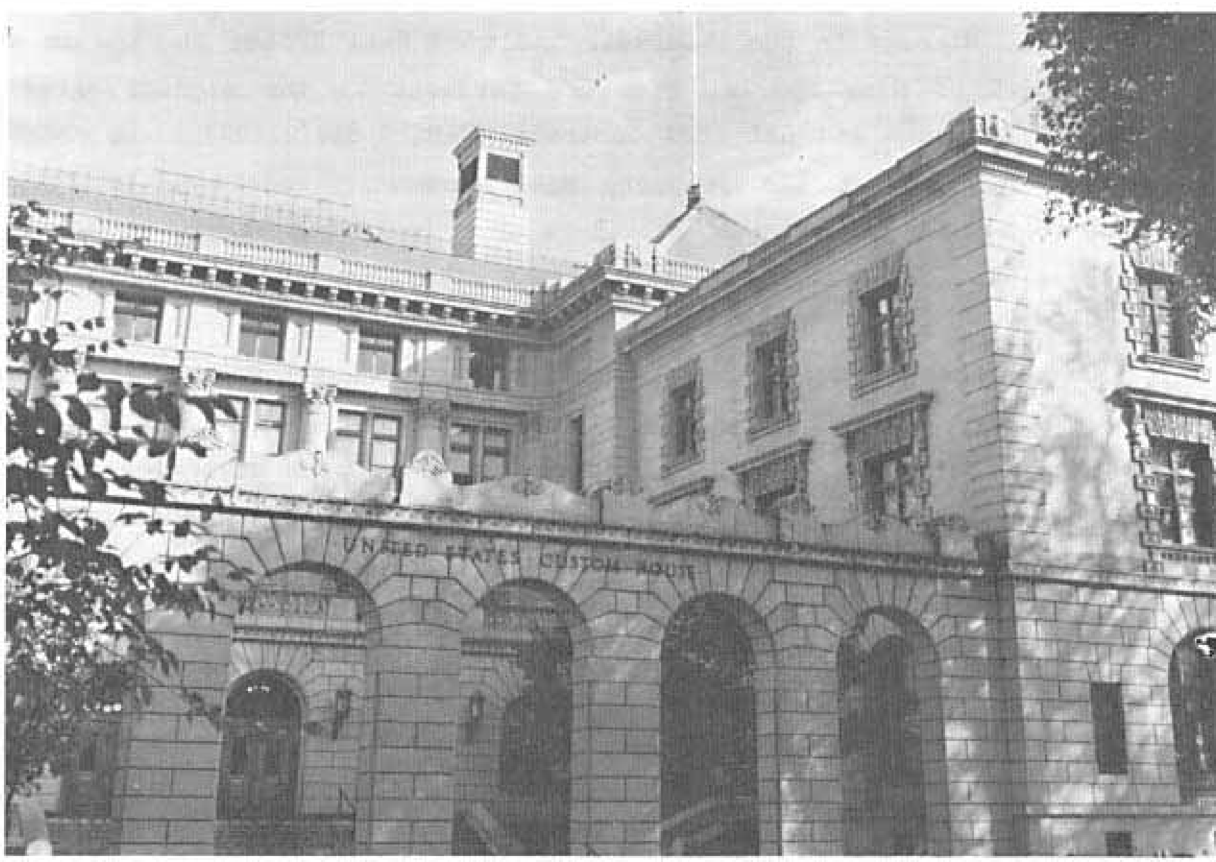
V. RESERVOIR OPERATION

General

The coordinated reservoir system started the 1983-84 operating year on 1 August 1983 with all reservoirs essentially full and it remained relatively full until after the first weekend in September. The gradual drawdown of the reservoir system that occurred in September and October primarily for power purposes was interrupted in November as streamflows increased markedly due to much above normal precipitation. Several reservoirs stopped drafting and some actually filled during November. A relatively rapid drawdown of the reservoir system was then required during December to keep reservoirs below flood control rule curves and this draft rate was continued in January and February because rule curves were lowered due to volume runoff forecasts.

Inflows began to increase in April 1984 but the increases were moderate due to persistent below normal temperatures in late April, May and June. The reservoir system, including Treaty storage, was regulated on a daily basis for flood control starting 19 April since the flow in the lower river was near the initial control flow. Operation of some reservoirs for flood control continued until 14 July 1984 when all resumed normal operation. The coordinated reservoir system was more than 98% full on 31 July 1984 and was therefore officially declared full for Coordination Agreement purposes. All available reservoir space however did not fill by about one million acre-feet, mostly non-Treaty space in Canadian reservoirs plus a small amount in Grand Coulee. Even so, operating year 1983-84 did see significant reservoir filling accomplishments since the initial fill of Revelstoke did take place, as well as large amounts of non-Treaty space in Mica were refilled. The hydropower system also replaced reductions in output from thermal plants in the U.S. Northwest. WNP-2 was

ARMY CORPS OF ENGINEERS. Treaty support staff, from left to right, sitting: Nicholas A. Dodge, Brig. Gen. George R. Robertson, and Herbert H. Kennon; standing; Wm. J. McGinnis, Gary R. Flightner, Douglas D. Speers, Gordon G. Green, and Paul E. Castro. Below is the U.S. Custom House in Portland, Oregon, completed in 1901 and the office of the North Pacific Division since 4 June 1954 and the Reservoir Control Center since it was established in July 1968. The National Weather Service Northwest River Forecast Center has been located here since it was established in January 1950.



still not commercial on 30 September 1984 and Trojan, which shut down on 27 April 1984 and was scheduled to return to service during the summer, was still not back on-line by 30 September 1984.

In 1984 U.S. reservoirs were operated again to provide flows for the downstream migration of juvenile anadromous fish. However, it was the first time that U.S. power system operating plans reduced firm load carrying capability to save water for the Northwest Power Planning Council's Fish and Wildlife Program which specifies a water budget for use during the 15 April to 15 June period. Above average flows in the Snake River enabled fishery flows to be provided without any special regulation. The 3.45 maf water budget for Priest Rapids was fully utilized between 28 April and 4 June 1984.

Mica Reservoir

As shown in chart 5, Mica reservoir was filled on 31 July 1983 to elevation 2471.8 ft, slightly above its normal full pool elevation of 2470.4 ft. Storage in the reservoir included full Treaty storage as well as 0.17 maf of Mica Special storage pursuant to the storage agreement between B.C. Hydro and BPA (BPA contract DE-MS79-83BP91290). In order to minimize spilling at the project, Mica reservoir continued to fill in August to a peak elevation of 2474.3 ft on 2 September before it was drawn down to elevation 2472.0 ft by 30 September 1983.

Generation at Mica was curtailed on 9 and 10 October 1983 to reduce the flow of the Columbia River at Revelstoke. The curtailment of generation was to facilitate closure of the Revelstoke diversion tunnel on 11 October. Subsequent to the closure, discharge at Mica was increased above the Detailed Operating Plan target releases to transfer the Mica

Special storage as well as other non-Treaty Storage from Mica reservoir to assist filling of the Revelstoke reservoir. This operation continued until mid-January, except for a period from 24 October to 21 November when Mica discharges were reduced to avoid exceeding the maximum filling rate at Revelstoke. Mica reservoir was drafted to an elevation of 2424.7 ft by 18 January. Mica reservoir continued to draft through February and March, and then on 16 April 1984 reached its lowest elevation of the year, 2387.6 ft. This was much lower than the level to which Mica reservoir would have been drafted without the need for Revelstoke initial filling storage transfers.

Mica reservoir began refilling when inflows increased in late April, 1984. Earlier, pursuant to the non-Treaty storage agreement with BPA, B.C. Hydro had declared 0.44 maf and 2.0 maf storage spaces at Mica available for Inactive and Active storages respectively. This permitted the actual Mica discharges to be reduced below the Detailed Operating Plan targets during periods when B.C. Hydro and/or BPA stored into these spaces, thus accelerating the refilling process. B.C. Hydro began storing into the non-Treaty storage spaces in March, and BPA began in April.

From May until mid-June 1984, even with zero discharge, the Mica project refilled very slowly due to a much lower than normal runoff in this period. The runoff increased to above normal after mid-June and peaked at 114,730 cfs on 29 June. The project continued to fill through July and reached elevation 2462.1 ft on 31 July. The Treaty storage space at Mica was filled on 2 August 1984. As the inflow was higher than B.C. Hydro's system load requirements, the reservoir continued to fill to a peak elevation of 2472.3 ft on 28 August. The inflow receded in September and Mica was then drafted to elevation 2471.0 ft, and maintained at that level through September.

Arrow Reservoir

As shown in chart 6, the Treaty storage space in Arrow reservoir was filled on 13 July 1983. The reservoir surcharged to elevation 1446.0 ft by 19 July and the surcharge storage was designated as Arrow Special storage to be used to fill the Revelstoke reservoir as per BPA contract DE-MS79-83BP91290 with B.C. Hydro. During August and September, Arrow reservoir discharged streamflows at the project, maintaining full Treaty storages at Mica and Arrow reservoirs. Streamflows at Arrow during this period receded to as low as 30,000 cfs.

Treaty storage draft began 2 October 1983 when Arrow increased its discharge to 35,000 cfs. Subsequent to the Revelstoke project reservoir elevation reaching the spillway intake level, Treaty storage released from Mica was held in the Revelstoke reservoir. Since the Arrow inflow was well below normal during this period, Arrow Lake dropped approximately seven feet to elevation 1438.0 ft by 27 October. From November 1983 until January 1984 Arrow reservoir storage was basically operated close to tne Flood Control Rule Curve, with project outflow varying between 30,000 cfs and 65,000 cfs.

Discharge at Arrow was increased up to 90,000 cfs in February and March 1984 to deliver Treaty storage for downstream generation requirements. The reservoir was drawn down approximately 30 ft to elevation 1391.2 ft by 19 March, its lowest level for the current operating year. On 24 March, the discharge at Arrow was reduced to 5,000 cfs because of the high runoff in the lower Columbia River. With the project outflow at approximately 5,000 cfs, Arrow continued to fill through April to elevation 1402.5 ft by 2 May before discharges were increased to help fill Grand Coulee reservoir. As a result, Arrow Lake was drawn down approximately 8 ft to elevation 1395.0 ft by 26 May before the project outflows were reduced to 5,000 cfs to resume filling.

Inflow into Arrow increased in June and July, peaking at 101,370 cfs on 30 June 1984. Arrow was able to fill quickly during this period and on 27 July, the Treaty space at Arrow was considered completely filled after accounting for Treaty storage at Revelstoke. Arrow reservoir discharge was then increased to match project streamflows. This caused Arrow reservoir to draft to elevation 1436.1 ft by 31 August. During September Revelstoke was able to discharge sufficient storage to maintain Arrow near elevation 1436.0 ft.

Duncan Reservoir

As shown in chart 7, Duncan reservoir was filled to its normal full pool elevation 1892.0 ft on 24 July 1983. During August and September, the project discharged inflow to maintain the reservoir near full pool. On 29 September, the project outflow was increased to 4,000 cfs to help fill Kootenay Lake. In early November above normal precipitation and the subsequent high runoff refilled the reservoir to 1887.6 ft on 19 November, slightly below its Operating Rule Curve.

Duncan project outflow was increased to 10,000 cfs during December 1983 to deliver Treaty storage, drafting the reservoir to elevation 1857.5 ft by 31 December. The reservoir continued to draft and on 5 March 1984 reached elevation 1804.2 ft, its lowest level for the current operating year. At this elevation, the reservoir was approximately 3.5 ft below its Flood Control Rule Curve. The project then discharged inflow until early April.

Duncan reservoir began refilling on 8 April 1984 wnen the project outflow was reduced to 100 cfs. Between 3 and 10 May the discharge at the project was increased to 4,000 cfs to help maintain levels at Kootenay Lake. Duncan Lake resumed filling when the discharge was again reduced to 100 cfs on 11 May. The snowmelt runoff in May was well below normal because of the cooler weather, and the reservoir only filled approximately

10 ft to elevation 1822.3 ft by 31 May. Inflow into Duncan Lake increased to near normal after mid-June and peaked at 27,040 cfs on 29 June. The reservoir continued to fill through July and reached its normal full pool elevation 1892.0 ft on 29 July. The project then discharged inflow, maintaining the reservoir level at about 1892.0 ft through 30 September 1984.

Libby Reservoir

On 1 August 1983, Lake Koocanusa was at elevation 2458.7 ft as shown in chart 8. Higher releases in September and October to meet power requirements drafted Lake Koocanusa about 16 ft by 20 October. The project basically released minimum flows from late October until the middle of November when the discharges were increased to full powerhouse capacity, about 20,000 cfs. The lake drafted to elevation 2407.4 ft by 31 December, about 3 ft below the 1 January flood control requirement. Libby outflow was reduced to a minimum of 4,000 cfs on 10 February 1984 and the lake continued to draft slowly through mid-April. The lake was at its lowest level at elevation 2370.3 ft on 15 April about 23 ft below the variable refill curve.

Inflows to Libby began increasing in mid-May. The seasonal peak was reached on 17 June 1984 with a daily average inflow of 51,100 cfs. Inflows receded to less than 20,000 cfs by mid-July. Libby outflow was held between 3,200 cfs and 4,000 cfs during May and June except when an increase to 12,000 cfs was made for several hours on 16 June for the Libby Logger's Day Festival. Releases were increased in July to reduce the rate of fill. Lake Koocanusa was full at elevation 2459.0 ft on 31 July 1984. Spill was not required at Libby during the spring runoff season.

The lake was held full during the first half of August 1984 but then a drawdown for power generation purposes began that continued through September. Special efforts were made to keep the lake in the top 5 ft until after the first weekend in September. Lake Koocanusa was at elevation 2454.2 ft on Monday 3 September and then drafted to elevation 2450.2 by the end of September 1984.

The new fifth generating unit at Libby has been operated for test purposes during 1984 and is scheduled to be ready for commercial service by December 1984. Work on the other three additional units progressed to the stage that the manufacturer has delivered many of the components but these have been placed in storage. No additional work on these last three units is scheduled. The Libby reregulating dam remains halted by court action of September 1978.

Kootenay Lake

As shown in chart 9, after filling to its peak elevation in June 1983, Kootenay Lake was gradually drawn down through July and August according to the IJC Order, reaching elevation 1743.1 ft by 31 August. During the period from September to mid-November, Kootenay Lake releases were adjusted as necessary to maintain a discharge of about 18,000 cfs at the Brilliant project except for a short period between 14 and 23 September when Kootenay Lake releases were increased to about 25,000 cfs to meet B.C. Hydro's system load requirements. The reservoir filled to elevation 1745.0 ft, slightly below its IJC Rule Curve, on 16 November.

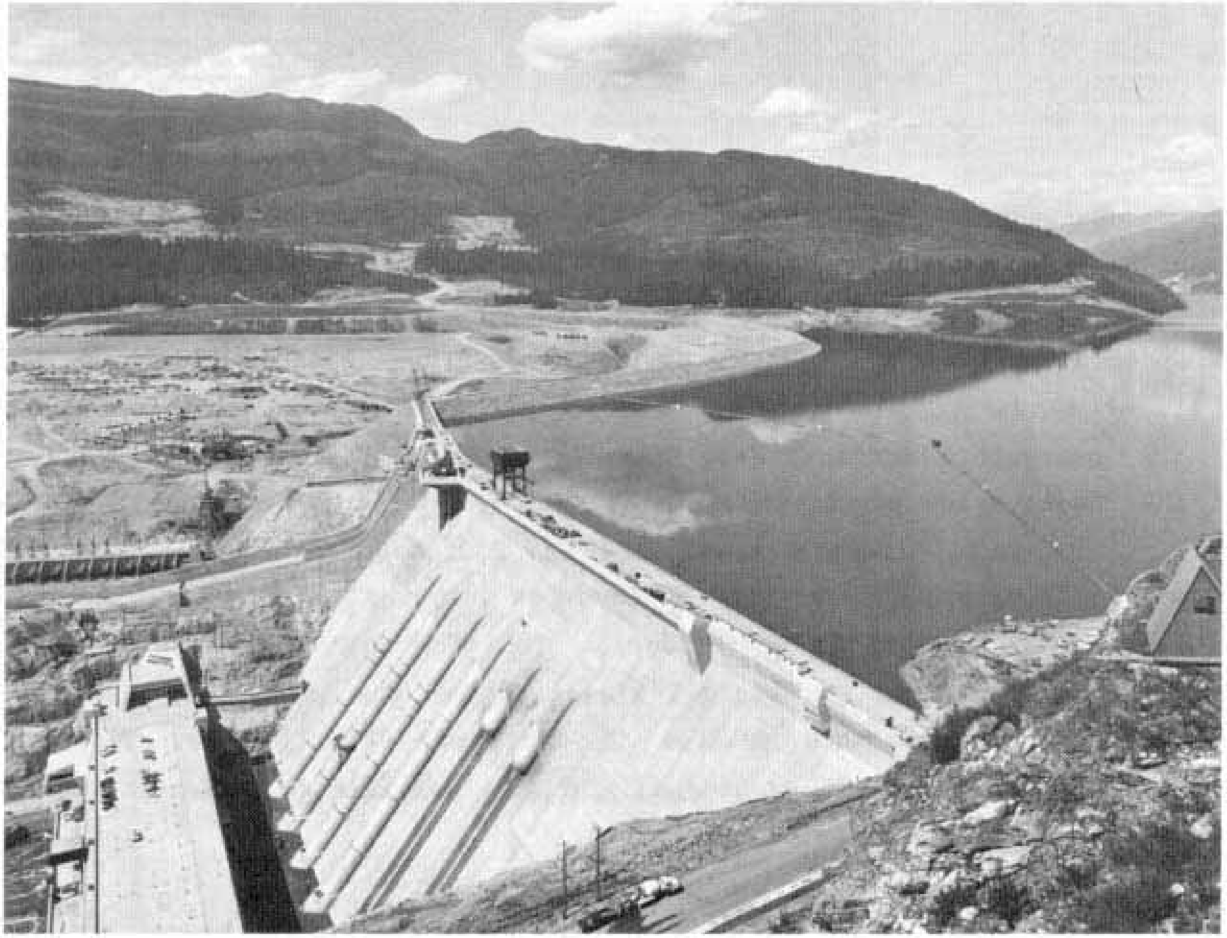
Kootenay Lake was held near elevation 1745.0 ft until mid-December 1983 when releases were increased up to 40,000 cfs for B.C. Hydro's generation requirements, resulting in a draft of the lake to elevation 1744.0 ft by 24 December. The lake was subsequently refilled to about 1745.0 ft in early January 1984. Kootenay Lake seasonal storage draft began soon thereafter and continued through to March, according to the IJC Rule Curve. The lake reached its lowest level, elevation 1738.7 ft, on 15 April.

The Kootenay Lake inflow began to increase due to snowmelt after mid-April. The lake was filled to elevation 1739.9 ft on 26 April and then drafted to 1739.5 ft by 2 May due to cool temperatures and less snowmelt in that period. Kootenay Lake refilling resumed on 15 May and continued through June to reach a peak elevation of 1747.5 ft on 29 June. The highest discharge from Kootenay Lake during this period was 53,000 cfs.

The inflow into Kootenay Lake receded in July and the lake was then drafted to elevation 1744.4 ft on 31 July 1984. Kootenay Lake continued to draft during August. Beginning 1 September, Kootenay Lake outflows were reduced to approximately 17,000 cfs to help refill the lake. This continued until 20 September before the outflow was further reduced to approximately 14,000 cfs. As a result, Kootenay Lake had reached elevation 1743.6 ft by 30 September 1984.

Revelstoke Project

The Revelstoke diversion tunnel was successfully closed on Tuesday morning, 11 October 1983. With zero discharge out of the project, the reservoir quickly filled to the 1700 ft elevation of the intermediate level outlets by 24 October. The project began spilling on 31 October, but the discharge was initially restricted to between 6,000 cfs and 14,000 cfs due to problems with a downstream cofferdam. A new cofferdam was completed later in November and the project was then able to increase its discharge up to 40,000 cfs, which permitted the release of the Treaty storage captured in the reservoir during the earlier period of zero discharge. Release of this Treaty storage was completed by the end of December. During this period Revelstoke continued to fill rapidly, but was not permitted to exceed a filling rate of 3 ft per day. The reservoir reached elevation 1830.0 ft on 18 January 1984, two days before the turbine unit testing was scheduled to begin.



REVELSTOKE PROJECT. A summer 1984 view of B.C. Hydro's Revelstoke Project from the left bank of the Columbia River. The reservoir began filling on 11 October 1983 and reached its highest elevation of the year, 1877.8 ft, on 13 August 1984. Three generating units were in operation by 30 September 1984.

Between 19 January and 19 February 1984, Revelstoke was held at elevation 1830.0 ft. Reservoir filling resumed on 20 February and the project outflow was then adjusted to gradually fill the reservoir at a rate which did not exceed 1 ft per day. The reservoir reached elevation 1865.0 ft on 19 April. The project then discharged inflow in order to maintain the reservoir level near elevation 1865.0 ft to facilitate observation of the Downie slide during the freshet period. After the freshet had peaked B. C. Hydro was given permission by the B.C. Government Water Comptroller to fill Revelstoke reservoir to elevation 1880.0 ft. The reservoir filled to elevation 1874.4 ft on 31 July. The reservoir continued to fill in August and reached its highest elevation for the year, 1877.8 ft on 13 August. It was then drafted to elevation 1873.7 ft by 31 August. Thereafter Revelstoke discharged inflow, maintaining elevation between 1874.0 and 1876.5 ft during September.

The first 450-mw generation unit at Revelstoke began commercial operation on 9 May 1984, the second unit on 15 May, and the third unit was in operation on 6 August. The fourth is scheduled for operation by December 1984. The installation of the last two units will be delayed several years. When fully developed with six units, Revelstoke will be the most powerful hydroelectric development in British Columbia with an installed capacity of 2700 mw.

During the period of initial filling, pursuant to the non-Treaty storage agreement with BPA, B. C. Hydro declared 1.86 maf of storage space available at Revelstoke for Inactive storage. B. C. Hydro began delivering in-lieu energy in early November 1983 to BPA for Inactive storage in Revelstoke. Filling of the Revelstoke reservoir was enhanced by transfering some of B. C. Hydro non-Treaty storage from Mica to Revelstoke during the period when the discharge at Mica exceeded the Detailed Operating Plan target releases. BPA began storing Inactive storage at Revelstoke about mid-April 1984. By 31 July, a total of 1.69 maf Inactive storage had been stored at Revelstoke.

VI. POWER AND FLOOD CONTROL ACCOMPLISHMENTS

General

During the period covered by this report, Duncan, Arrow, Mica, and Libby reservoirs were operated in accordance with the Columbia River Treaty. More specifically the operation of the reservoirs was in accordance with:

1. "Columbia River Treaty Hydroelectric Operating Plan - Assured Operating Plan for Operating Year 1983-84," dated September 1978.

2. "Detailed Operating Plan for Columbia River Treaty Storage - 1 August 1983 through 31 July 1984," dated September 1983.

3. "Columbia River Treaty Flood Control Operating Plan," dated October 1972.

Consistent with all Detailed Operating Plans prepared since the installation of generation at Mica, the 1983-84 Detailed Operating Plan was designed to achieve optimum power generation at-site in Canada and downstream in Canada and the United States, in accordance with paragraph 7 of Annex A of the Treaty. The 1983-84 Assured Operating Plan prepared in 1978, was used as the basis for the preparation of the 1983-84 Detailed Operating Plan.

Power

The Canadian Entitlement to downstream power benefits from Duncan, Arrow and Mica for the 1983-84 operating year had been purchased in 1964 by the Columbia Storage Power Exchange. In accordance with the Canadian Entitlement Exchange Agreement dated 13 August 1964, the U.S. Entity delivered capacity and energy to the CSPE participants.

The generation at downstream projects in the United States, delivered under the Canadian Entitlement Exchange Agreement was 495 average megawatts at rates up to 1,126 megawatts, from 1 August 1983 through 31 March 1984, and 468 average megawatts, at rates up to 1,172 megawatts, from 1 April 1984 through 31 July 1984. All CSPE power was used to meet Pacific Northwest loads.

The coordinated reservoir system was full on 1 August 1983 and after being drawn down during the 1983-84 operating year, was again full on 31 July 1984. The following table shows the status of the energy stored in the coordinated system in billions of kilowatt-hours at the end of each month compared to rule curves during the 1983-84 operating year:

Month	Rule Curve	Actual	Difference
August 1983	46.6	45.7	-0.9
September	44.3	43.7	-0.6
October	41.8	40.8	-1.0
November	38.0	39.3	1.3
December	33.2	32.3	-0.9
January 1984	19.9 1/	28.8	8.9
February	14.2 1/	23.0	8.8
March	15.2 1/	20.7	5.5
April	15.8 1/	20.2	4.4
May	27.7 1/	24.1	-3.6 2/
June	38.9 1/	39.8	0.9
July	46.7	45.8	-0.9

Notes:

1/ Rule curves were lowered due to volume runoff forecasts shown in table 1.

2/ Operation below rule curves were temporarily required to meet instream flows for juvenile fish outmigration.

The first quartile of BPA's industrial load was served with direct nonfirm service the entire year except during the period 1-14 November when service was provided by provisional draft of reservoirs. The following table shows BPA nonfirm and surplus firm sales in megawatt-hours to northwest and southwest utilities during the 1983-84 operating year.

Period	To Northwest Utilities		To Southwest Utilities	
	Nonfirm	Surplus Firm	Nonfirm	Surplus Firm
August 1983	559,623	-	1,851,562	66,196
September	419,853	-	85,315	192,000
October	18,902	-	0	384,600
November	77,336	-	919,033	210,779
December	354,789	175,680	1,112,616	136,233
January 1984	133,229	13,200	1,840,476	53,081
February	92,669	-	2,425,105	112,473
March	284,116	-	2,605,343	154,682
April	516,157	-	2,521,149	72,000
May	1,015,299	-	2,762,417	36,000
June	876,647	-	2,420,749	72,000
July	449,887	-	1,381,492	400,000
TOTAL	4,798,507	188,880	19,925,257	1,890,044

Flood Control

The Columbia reservoir system including Treaty projects in Canada began operating for flood control on 19 April 1984 because the flow in the lower Columbia River was above the 1 April computed initial controlled flow of 305,000 cfs and the forecasts indicated that the unregulated flow would be above 450,000 cfs in approximately 20 days. Arrow outflow was held near 5,000 cfs until the end of April although the flood control requests specified a release of 20,000 cfs. The difference in these two flows represents water stored in non-Treaty storage space and was done by mutual consent. Duncan outflow was reduced to minimum outflow of 100 cfs on 9 April to reduce the inflow to Kootenay Lake and to refill the Duncan reservoir. The reservoir system remained on flood control and releases were scheduled on a daily basis through 14 July. The discharges requested for flood control and refill purposes from 8 June through 14 July 1984 for Mica, Arrow and Duncan were 10,000 cfs, 15,000 cfs and 100 cfs respectively.

Flood control during the spring runoff was provided by the normal refill operation of the Treaty reservoirs and other storage reservoirs in the Columbia River Basin. The unregulated peak at The Dalles would have been 628,000 cfs on 23 June 1984 and it was controlled to a maximum of 375,000 cfs at Bonneville which occurred on several occasions. The peak inflow to Lower Granite was 244,800 cfs on 31 May; this is the highest inflow to the project since it became operational in April 1975. The peak flow into the John Day Project was 446,600 cfs on 31 May but storage at this project permitted the flow at Bonneville to be controlled to 375,000 cfs as discussed earlier. The observed peak stage at Vancouver, Washington was 13.1 ft and the unregulated stage would have been 22.5 ft, whereas floodstage is 16.0 ft. The peak daily flow at The Dalles during the operating year was 376,000 cfs on 27 June 1984. The observed and unregulated hydrographs for 1 July 1983 through 31 July 1984 at The Dalles are shown with a summary hydrograph on chart 12 for comparison with historical flows. Chart 13 shows the effect of Mica, Arrow, Duncan and Libby regulations on the flow at The Dalles.

Chart 14 documents the relative filling of Arrow and Grand Coulee during the principal filling period, and compares the coordinated regulation of the two reservoirs to guidelines in the Flood Control Operating Plan.

Table 1
Unregulated Runoff Volume Forecasts
Millions of Acre-Feet
1984

Forecast Date - 1st of	DUNCAN Most Probable 1 Apr - 31 Aug	ARROW Most Probable 1 Apr - 31 Aug	MICA Most Probable 1 Apr - 31 Aug	LIBBY Most Probable 1 Apr - 31 Aug	UNREGULATED RUNOFF COLUMBIA RIVER AT THE DALLES, OREGON Most Probable 1 Apr - 31 Jul
January	2.0	22.3	11.0	6.4	91.2
February	2.0	23.4	11.4	5.7	80.7
March	2.0	22.6	11.0	5.2	75.1
April	1.9	23.1	10.9	5.0	75.6
May	1.9	22.8	10.7	5.1	80.6
June	2.0	23.1	10.7	5.5	87.6
Actual	1.9	20.6	10.0	5.1	92.7

NOTE: These data were used in actual operations. Subsequent revisions have been made in some cases.

Table 2
95 Percent Confidence Forecast and Variable Energy Content Curve Mica 1984

		INITAL	JAN 1 TOTAL	FEB 1 TOTAL	MAR 1 TOTAL	APR 1 TOTAL	MAY 1 TOTAL	JUN 1 TOTAL
1	PROBABLE FEB 1 - JUL 31 INFLOW, KSFD [1]		4536.7	4702.4	4583.8	4567.4	4488.6	4362.1
2	95% FORECAST ERROR, KSFD		718.3	536.6	495.2	482.4	472.0	469.8
3	95% CONFIDENCE FEB 1 - JUL 31 INFLOW, KSFD [2]		3818.4	4165.8	4088.6	4085.0	4016.6	3892.3
4	OBSERVED FEB 1 - DATE INFLOW, KSFD				116.7	252.0	472.4	844.9
5	RESIDUAL 95% DATE - JUL 31 INFLOW, KSFD [3]		3818.4	4165.8	3971.9	3833.0	3544.2	3047.4
	ASSUMED FEB 1 - JUL 31 INFLOW, % OF VOLUME		100.0					
	ASSUMED FEB 1 - JUL 31 INFLOW, KSFD [4]		3818.4					
	MIN. FEB 1 - JUL 31 OUTFLOW, KSFD		2180.0					
	MIN. JAN 31 RESERVOIR CONTENT, KSFD [5]		1890.8					
	MIN. JAN 31 RESERVOIR ELEVATION, FT [6]		2437.7					
	JAN 31 ECC, FT [7]		2436.3					
	BASE ECC, FT	2441.5						
	LOWER LIMIT, FT	2425.2						
	ASSUMED MAR 1 - JUL 31 INFLOW, % OF VOLUME		97.8	97.8				
	ASSUMED MAR 1 - JUL 31 INFLOW, KSFD [4]		3734.4	4074.2				
	MIN. MAR 1 - JUL 31 OUTFLOW, KSFD		1760.0	1760.0				
	MIN. FEB 28 RESERVOIR CONTENT, KSFD [5]		1554.8	1215.0				
	MIN. FEB 28 RESERVOIR ELEVATION, FT [6]		2430.6	2423.1				
	FEB 28 ECC, FT [7]		2425.5	2423.1				
	BASE ECC, FT	2431.2						
	LOWER LIMIT, FT	2412.2						
	ASSUMED APR 1 - JUL 31 INFLOW, % OF VOLUME		95.4	95.4	97.6			
	ASSUMED APR 1 - JUL 31 INFLOW, KSFD [4]		3642.8	3974.2	3876.6			
	MIN. APR 1 - JUL 31 OUTFLOW, KSFD		1295.0	1295.0	1295.0			
	MIN. MAR 31 RESERVOIR CONTENT, KSFD [5]		1181.4	850.0	947.6			
	MIN. MAR 31 RESERVOIR ELEVATION, FT [6]		2422.4	2414.9	2417.1			
	MAR 31 ECC, FT [7]		2413.7	2413.7	2413.7			
	BASE ECC, FT	2419.8						
	LOWER LIMIT FT	2402.1						
	ASSUMED MAY 1 - JUL 31 INFLOW, % OF VOLUME		91.0	91.0	93.1	95.4		
	ASSUMED MAY 1 - JUL 31 INFLOW, KSFD [4]		3474.7	3790.9	3697.8	3656.7		
	MIN. MAY 1 - JUL 31 OUTFLOW, KSFD		920.0	920.0	920.0	920.0		
	MIN. APR 30 RESERVOIR CONTENT, KSFD [5]		974.5	658.3	751.4	792.5		
	MIN. APR 30 RESERVOIR ELEVATION, FT [6]		2417.7	2410.5	2412.6	2413.6		
	APR 30 ECC, FT [7]		2404.4	2404.4	2404.4	2404.4		
	BASE ECC, FT	2410.6						
	LOWER LIMIT, FT	2400.7						
	ASSUMED JUN 1 - JUL 31 INFLOW, % OF VOLUME		74.1	74.1	75.8	77.7	81.5	
	ASSUMED JUN 1 - JUL 31 INFLOW, KSFD [4]		2829.4	3086.9	3010.7	2978.2	2888.5	
	MIN. JUN 1 - JUL 31 OUTFLOW, KSFD		610.0	610.0	610.0	610.0	610.0	
	MIN. MAY 31 RESERVOIR CONTENT, KSFD [5]		1309.8	1052.3	1128.5	1161.0	1250.7	
	MIN. MAY 31 RESERVOIR ELEVATION, FT [6]		2425.2	2419.5	2421.2	2421.9	2423.9	
	MAY 31 ECC, FT [7]		2416.9	2416.9	2416.9	2416.9	2416.9	
	BASE ECC, FT	2423.0						
	LOWER LIMIT, FT	2400.7						
	ASSUMED JUL 1 - JUL 31 INFLOW, % OF VOLUME		36.9	36.9	37.8	38.7	40.6	49.6
	ASSUMED JUL 1 - JUL 31 INFLOW, KSFD [4]		1409.0	1537.2	1501.4	1483.4	1438.9	1517.6
	MIN. JUL 1 - JUL 31 OUTFLOW, KSFD		310.0	310.0	310.0	310.0	310.0	310.0
	MIN. JUN 31 RESERVOIR CONTENT, KSFD [5]		2430.2	2302.0	2337.8	2355.8	2400.3	2321.6
	MIN. JUN 31 RESERVOIR ELEVATION, FT [6]		2448.9	2446.3	2447.0	2447.4	2448.3	2446.7
	JUN 30 ECC, FT [7]		2446.6	2446.3	2446.6	2446.6	2446.6	2446.6
	BASE ECC, FT	2451.2						
	LOWER LIMIT, FT	2400.7						
	JUL 31 ECC, FT		2470.4	2470.4	2470.4	2470.4	2470.4	2470.4

1/ DEVELOPED BY CANADIAN ENTITY
2/ LINE 1 - LINE 2
3/ LINE 3 - LINE 4
4/ PRECEDING LINE X LINE 5
5/ FULL CONTENT (3529.2 KSFD) PLUS PRECEDING LINE LESS LINE PRECEDING THAT (USABLE STORAGE)
6/ FROM RESERVOIR ELEVATION - STORAGE CONTENT TABLE DATED FEB. 21, 1973.
7/ LOWER OF ELEVATION ON PRECEDING LINE OR ELEVATION DETERMINED PRIOR TO YEAR.

Table 3
95 Percent Confidence Forecast and Variable Energy Content Curve
Arrow 1984

	INITAL	JAN 1 TOTAL	FEB 1 TOTAL	MAR 1 TOTAL	APR 1 LOCAL	MAY 1 LOCAL	JUN 1 LOCAL
1 PROBABLE FEB 1 - JUL 31 INFLOW, KSFD [1]...............		9684.9	10076.7	10020.0	5592.8	5604.7	5493.9
2 95% FORECAST ERROR, KSFD		1546.3	1168.6	1071.6	564.0	517.1	482.9
3 95% CONFIDENCE DATE - JUL 31 INFLOW, KSFD [2]..........		8138.6	8908.1	8948.4	5028.8	5087.6	5011.0
4 OBSERVED FEB 1 - DATE INFLOW, KSFD				895.1	608.1	995.6	1858.3
5 RESIDUAL 95% DATE - JUL 31 INFLOW, KSFD[3].............		8138.6	8908.1	8520.1	4420.7	4092.0	3152.7
ASSUMED FEB 1 - JUL 31 INFLOW, % OF VOLUME		100.0					
ASSUMED FEB 1 - JUL 31 INFLOW, KSFD [4]...............		8138.6					
MIN. FEB 1 - JUL 31 OUTFLOW, KSFD		1454.0					
MICA REFILL REQUIREMENTS, KSFD [8].....................		1707.0					
MIN. JAN 31 RESERVOIR CONTENT, KSFD [5]...............		0					
MIN. JAN 31 RESERVOIR ELEVATION, FT [6]...............		1377.9					
JAN 31 ECC, FT [7]....................................		1389.3					
BASE ECC, FT	1413.0						
LOWER LIMIT, FT	1389.3						
ASSUMED MAR 1 - JUL 31 INFLOW, % OF VOLUME		97.5	97.5				
ASSUMED MAR 1 - JUL 31 INFLOW, KSFD [4]...............		7935.1	8685.4				
MIN. MAR 1 - JUL 31 OUTFLOW, KSFD		1314.0	1314.0				
MICA REFILL REQUIREMENTS, KSFD [8].....................		2207.1	2314.2				
MIN. FEB 28 RESERVOIR CONTENT, KSFD [5]...............		0	0				
MIN. FEB 28 RESERVOIR ELEVATION, FT [6]...............		1377.9	1377.9				
FEB 28 ECC, FT [7]....................................		1381.2	1381.2				
BASE ECC, FT	1400.7						
LOWER LIMIT, FT	1381.2						
ASSUMED APR 1 - JUL 31 INFLOW, % OF VOLUME		94.7	94.7	97.1			
ASSUMED APR 1 - JUL 31 INFLOW, KSFD [4]...............		7707.3	8435.9	8273.0			
MIN. APR 1 - JUL 31 OUTFLOW, KSFD		1159.0	1159.0	1159.0			
MICA REFILL REQUIREMENTS, KSFD [8].....................		2731.3	2731.3	2731.3			
MIN. MAR 31 RESERVOIR CONTENT, KSFD [5]...............		0	0	0			
MIN. MAR 31 RESERVOIR ELEVATION, FT [6]...............		1377.9	1377.9	1377.9			
MAR 31 ECC, FT [7]....................................		1380.8	1380.8	1380.8			
BASE ECC, FT	1412.2						
LOWER LIMIT, FT	1380.8						
ASSUMED MAY 1 - JUL 31 INFLOW, % OF VOLUME		89.0	89.0	91.2	92.7		
ASSUMED MAY 1 - JUL 31 INFLOW, KSFD [4]...............		7243.4	7928.2	7770.3	4098.0		
MIN. MAY 1 - JUL 31 OUTFLOW, KSFD		1009.0	1009.0	1009.0	1009.0		
MICA REFILL REQUIREMENTS, KSFD [8].....................		3128.1	3128.1	3128.1	920.0		
MIN. APR 30 RESERVOIR CONTENT, KSFD [5]...............		473.3	0	0	-429.4		
MIN. APR 30 RESERVOIR ELEVATION, FT [6]...............		1377.9	1377.9	1377.9	1377.9		
APR 30 ECC, FT [7]....................................		1388.9	1377.9	1377.9	1377.9		
BASE ECC, FT	1415.7						
LOWER LIMIT, FT	1377.9						
ASSUMED JUN 1 - JUL 31 INFLOW, % OF VOLUME		68.7	68.7	70.4	57.9	73.3	
ASSUMED JUN 1 - JUL 31 INFLOW, KSFD [4]...............		5591.2	6119.8	5998.2	3001.7	299.4	
MIN. JUN 1 - JUL 31 OUTFLOW, KSFD		854.0	854.0	854.0	854.0	854.0	
MICA REFILL REQUIREMENTS, KSFD [8].....................		2591.5	2591.5	2591.5	610.0	610.0	
MIN. MAY 31 RESERVOIR CONTENT, KSFD [5]...............		1443.9	905.3	1026.9	821.9	824.2	
MIN. MAY 31 RESERVOIR ELEVATION, FT [6]...............		1408.1	1397.8	1400.4	1396.2	1396.2	
MAY 31 ECC, FT [7]....................................		1408.1	1377.9	1400.4	1396.2	1396.2	
ASSUMED JUL 1 - JUL 31 INFLOW, % OF VOLUME		31.9	31.9	32.7	29.2	31.5	43.0
ASSUMED JUL 1 - JUL 31 INFLOW, KSFD [4]...............		2596.2	2841.7	2786.1	1290.8	1289.0	1355.7
MIN. JUL 1 - JUL 31 OUTFLOW, KSFD		434.0	434.0	434.0	434.0	434.0	434.0
MICA REFILL REQUIREMENTS, KSFD [8].....................		1211.9	1211.9	1211.9	310.0	310.0	310.0
MIN. JUN 30 RESERVOIR CONTENT, KSFD [5]...............		2926.3	2883.8	2439.4	2412.8	2414.6	2347.9
MIN. JUN 30 RESERVOIR ELEVATION, FT [6]...............		1429.0	1424.8	1425.8	1425.4	1425.4	1424.3
JUN 30 ECC, FT [7]....................................		1429.0	1424.8	1425.8	1425.4	1425.4	1424.3
BASE ECC, FT	1443.6						
LOWER LIMIT, FT	1377.9						
JUL 31 ECC, FT	1444.0	1444.0	1444.0	1444.0	1444.0	1444.0	1444.0

1/ DEVELOPED BY CANADIAN ENTITY
2/ LINE 1 - LINE 2
3/ LINE 3 - LINE 4
4/ PRECEDING LINE X LINE 5
5/ FOR ARROW LOCAL: FULL CONTENT (3579.6 KSFD) LESS LINE PRECEDING PLUS LINE PRECEDING THAT LESS LINE PRECEDING THAT
FOR ARROW TOTAL: FULL CONTENT (3579.6 KSFD) PLUS TWO PRECEDING LINES LESS LINE PRECEDING THAT
6/ FROM RESERVOIR ELEVATION - STORAGE CONTENT TABLE DATED FEBRUARY 21, 1973.
7/ LOWER OF ELEVATION ON PRECDING LINE OR ELEVATION DETERMINED PRIOR TO YEAR.
8/ FOR ARROW LOCAL: MICA MINIMUM POWER DISCHARGES.
FOR ARROW TOTAL: MICA FULL CONTENT LESS ENERGY CONTENT CURVE.

Table 4
95 Percent Confidence Forecast and Variable Energy Content Curve
Duncan 1984

		INITAL	JAN 1 TOTAL	FEB 1 TOTAL	MAR 1 TOTAL	APR 1 TOTAL	MAY 1 TOTAL	JUN 1 TOTAL
1	PROBABLE FEB 1 - JUL 31 INFLOW, KSFD [1]		862.7	886.7	857.9	827.2	863.7	858.5
2	95% FORECAST ERROR KSFD		154.7	116.9	113.2	106.6	94.2	93.0
3	95% CONFIDENCE DATE - JUL 31 INFLOW, KSFD [2]		708.0	769.8	744.7	720.6	769.5	765.5
4	OBSERVED FEB 1 - DATE INFLOW, KSFD				17.4	41.5	92.7	190.8
5	RESIDUAL 95% DATE - JUL 31 INFLOW, KSFD [3]		708.0	769.8	727.3	679.1	676.8	574.7
	ASSUMED FEB 1 - JUL 31 INFLOW, % OF VOLUME		100.0					
	ASSUMED FEB 1 - JUL 31 INFLOW, KSFD [4]		708.0					
	MIN. FEB 1 - JUL 31 OUTFLOW, KSFD		18.1					
	MIN. JAN 31 RESERVOIR CONTENT, KSFD [5]		15.9					
	MIN. JAN 31 RESERVOIR ELEVATION, FT [6]		1798.0					
	JAN 31 ECC, FT [7]		1798.0					
	BASE ECC, FT	1842.5						
	LOWER LIMIT, FT	1800.2						
	ASSUMED MAR 1 - JUL 31 INFLOW, % OF VOLUME		97.8	97.8				
	ASSUMED MAR 1 - JUL 31 INFLOW, KSFD [4]		692.4	752.9				
	MIN. MAR 1 - JUL 31 OUTFLOW, KSFD		15.3	15.3				
	MIN. FEB 28 RESERVOIR CONTENT, KSFD [5]		28.7	-31.8				
	MIN. FEB 28 RESERVOIR ELEVATION, FT [6]		1800.8	1794.2				
	FEB 28 ECC, FT [7]		1800.8	1799.0				
	BASE ECC, FT	1842.4						
	LOWER LIMIT, FT	1800.7						
	ASSUMED APR 1 - JUL 31 INFLOW, % OF VOLUME		95.4	95.4	97.5			
	ASSUMED APR 1 - JUL 31 INFLOW, KSFD [4]		675.4	734.4	709.1			
	MIN. APR 1 - JUL 31 OUTFLOW, KSFD		12.2	12.2	12.2			
	MIN. MAR 31 RESERVOIR CONTENT, KSFD [5]		42.6	-16.4	8.9			
	MIN. MAR 31 RESERVOIR ELEVATION, FT [6]		1803.5	1794.2	1796.4			
	MAR 31 ECC, FT [7]		1803.5	1794.6	1796.4			
	BASE ECC, FT	1842.2						
	LOWER LIMIT, FT	1796.0						
	ASSUMED MAY 1 - JUL 31 INFLOW, % OF VOLUME		90.3	90.3	92.2	94.6		
	ASSUMED MAY 1 - JUL 31 INFLOW, KSFD [4]		639.3	695.1	670.6	642.4		
	MIN. MAY 1 - JUL 31 OUTFLOW, KSFD		9.2	9.2	9.2	9.2		
	MIN. APR 30 RESERVOIR CONTENT, KSFD [5]		75.7	19.9	44.4	72.6		
	MIN. APR 30 RESERVOIR ELEVATION, FT [6]		1809.5	1798.9	1803.9	1809.0		
	APR 30 ECC, FT [7]		1809.5	1798.9	1803.9	1809.0		
	BASE ECC, FT	1834.2						
	LOWER LIMIT, FT	1794.2						
	ASSUMED JUN 1 - JUL 31 INFLOW, % OF VOLUME		70.5	70.5	72.0	73.9	78.1	
	ASSUMED JUN 1 - JUL 31 INFLOW, KSFD [4]		499.1	542.7	523.7	501.9	528.6	
	MIN. JUN 1 - JUL 31 OUTFLOW, KSFD		6.1	6.1	6.1	6.1	6.1	
	MIN. MAY 31 RESERVOIR CONTENT, KSFD [5]		212.8	169.2	188.2	210.0	183.3	
	MIN. MAY 31 RESERVOIR ELEVATION, FT [6]		1830.9	1824.5	1827.3	1830.5	1826.6	
	MAY 31 ECC, FT [7]		1830.9	1824.5	1827.3	1830.5	1826.6	
	BASE ECC, FT	1848.6						
	LOWER LIMIT, FT	1794.2						
	ASSUMED JUL 1 - JUL 31 INFLOW, % OF VOLUME		33.3	33.3	34.0	34.9	36.9	47.2
	ASSUMED JUL 1 - JUL 31 INFLOW, KSFD [4]		235.8	256.3	247.3	237.0	249.7	271.3
	MIN. JUL 1 - JUL 31 OUTFLOW, KSFD		3.1	3.1	3.1	3.1	3.1	3.1
	MIN. JUN 30 RESERVOIR CONTENT, KSFD [5]		473.1	452.6	461.6	471.9	459.2	437.6
	MIN. JUN 30 RESERVOIR ELEVATION, FT [6]		1864.9	1862.4	1863.5	1864.7	1863.2	1860.5
	JUN 30 ECC, FT [7]		1864.9	1862.4	1863.5	1864.7	1863.2	1860.5
	BASE ECC, FT	1875.4						
	LOWER LIMIT, FT	1794.2						
	JUL 31 ECC, FT	1892.0	1892.0	1892.0	1892.0	1892.0	1892.0	1892.0

1/ DEVELOPED BY CANADIAN ENTITY
2/ LINE 1 - LINE 2
3/ LINE 3 - LINE 4
4/ PRECEDING LINE X LINE 5
5/ FULL CONTENT (705.8 KSFD) PLUS PRECEDING LINE LESS LINE PRECEDING THAT
6/ FROM RESERVOIR ELEVATION - STORAGE CONTENT TABLE DATED FEBRUARY 21, 1973.
7/ LOWER OF ELEVATION ON PRECEDING LINE OR ELEVATION DETERMINED PRIOR TO YEAR.

Table 5
95 Percent Confidence Forecast and Variable Energy Content Curve
Libby 1984

		INITAL	JAN 1 TOTAL	FEB 1 TOTAL	MAR 1 TOTAL	APR 1 TOTAL	MAY 1 TOTAL	JUN 1 TOTAL
1	PROBABLE JAN 1 - JUL 31 INFLOW, KSFD		3232.7	2952.2	2698.9	2585.5	2636.3	2823.4
2	95% FORECAST ERROR, KSFD		877.2	598.8	546.6	495.1	414.7	348.4
3	OBSERVED JAN 1 - DATE INFLOW, KSFD		0.0	110.8	197.2	293.5	483.5	895.5
4	95% CONF. DATE - JUL 31 INFLOW, KSFD [1]..............		2355.5	2242.7	1955.1	1796.8	1738.1	1579.6
	ASSUMED FEB 1 - JUL 31 INFLOW, % OF VOLUME		96.94					
	ASSUMED FEB 1 - JUL 31 INFLOW, KSFD [2]...............		2283.4					
	FEB MINIMUM FLOW REQUIREMENT, CFS [3].................		3000.0					
	MIN. FEB 1 - JUL 31 OUTFLOW, KSFD [4].................		543.0					
	MIN. JAN 31 RESERVOIR CONTENT, KSFD [5]...............		770.1					
	MIN. JAN 31 RESERVOIR ELEVATION, FT [6]...............		2362.5					
	JAN 31 ECC, FT [7].....................................		2362.5					
	BASE ECC, FT	2407.6						
	LOWER LIMIT, FT	2330.4						
	ASSUMED MAR 1 - JUL 31 INFLOW, % OF VOLUME		94.17	97.14				
	ASSUMED MAR 1 - JUL 31 INFLOW, KSFD [2]...............		2218.1	2178.5				
	MAR MINIMUM FLOW REQUIREMENT, CFS [3].................		3000.0	3000.0				
	MIN. MAR 1 - JUL 31 OUTFLOW, KSFD [4].................		459.0	459.0				
	MIN. FEB 28 RESERVOIR CONTENT, KSFD [5]...............		751.4	791.4				
	MIN. FEB 28 RESERVOIR ELEVATION, FT [6]...............		2361.0	2364.1				
	FEB 28 ECC, FT [7].....................................		2361.0	2364.1				
	BASE ECC, FT	2406.1						
	LOWER LIMIT, FT	2307.1						
	ASSUMED APR 1 - JUL 31 INFLOW, % OF VOLUME		90.79	93.66	96.42			
	ASSUMED APR 1 - JUL 31 INFLOW, KSFD [2]...............		2138.5	2100.5	1885.1			
	APR MINIMUM FLOW REQUIREMENT, CFS [3].................		3000.0	3000.0	3000.0			
	MIN. APR 1 - JUL 31 OUTFLOW, KSFD [4].................		366.0	366.0	366.0			
	MIN. MAR 31 RESERVOIR CONTENT, KSFD [5]...............		738.0	776.0	991.4			
	MIN. MAR 31 RESERVOIR ELEVATION, FT [6]...............		2360.0	2362.9	2378.7			
	MAR 31 ECC, FT [7].....................................		2360.0	2362.9	2378.7			
	BASE ECC, FT	2404.9						
	LOWER LIMIT, FT	2289.0						
	ASSUMED MAY 1 - JUL 31 INFLOW, % OF VOLUME		81.71	84.29	86.77	90.00		
	ASSUMED MAY 1 - JUL 31 INFLOW, KSFD [2]...............		1924.7	1890.4	1696.4	1617.1		
	MAY MINIMUM FLOW REQUIREMENT, CFS [3].................		3000.0	3000.0	3000.0	3000.0		
	MIN. MAY 1 - JUL 31 OUTFLOW, KSFD [4].................		276.0	276.0	276.0	276.0		
	MIN. APR 30 RESERVOIR CONTENT, KSFD [5]...............		861.8	896.1	1090.1	1169.4		
	MIN. APR 30 RESERVOIR ELEVATION, FT [6]...............		2369.5	2372.0	2385.6	2391.0		
	APR 30 ECC, FT [7].....................................		2369.5	2372.0	2385.6	2391.0		
	BASE ECC, FT	2403.4						
	LOWER LIMIT, FT	2287.0						
	ASSUMED JUN 1 - JUL 31 INFLOW, % OF VOLUME		52.75	54.42	56.02	58.10	64.56	
	ASSUMED JUN 1 - JUL 31 INFLOW, KSFD [2]...............		1242.5	1220.5	1095.3	1043.9	1122.1	
	JUN MINIMUM FLOW REQUIREMENT, CFS [3].................		3000.0	3000.0	3000.0	3000.0	3000.0	
	MIN. JUN 1 - JUL 31 OUTFLOW, KSFD [4].................		183.0	183.0	183.0	183.0	183.0	
	MIN. MAY 31 RESERVOIR CONTENT, KSFD [5]...............		1451.0	1473.0	1598.2	1649.6	1571.4	
	MIN. MAY 31 RESERVOIR ELEVATION, FT [6]...............		2408.0	2409.4	2416.1	2418.8	2414.7	
	MAY 31 ECC, FT [7].....................................		2408.0	2409.4	2416.1	2418.8	2414.7	
	BASE ECC, FT	2427.1						
	LOWER LIMIT, FT	2287.0						
	ASSUMED JUL 1 - JUL 31 INFLOW, % OF VOLUME		18.97	19.57	20.15	20.90	23.22	35.97
	ASSUMED JUL 1 - JUL 31 INFLOW, KSFD [2]...............		446.8	438.9	394.0	375.5	403.6	568.2
	JUL MINIMUM FLOW REQUIREMENT, CFS [3].................		3000.0	3000.0	3000.0	3000.0	3000.0	3000.0
	MIN. JUL 1 - JUL 31 OUTFLOW, KSFD [4].................		93.0	93.0	93.0	93.0	93.0	93.0
	MIN. JUN 30 RESERVOIR CONTENT, KSFD [5]...............		2156.7	2164.6	2209.5	2228.0	2199.9	2035.3
	MIN. JUN 30 RESERVOIR ELEVATION, FT [6]...............		2443.0	2443.0	2445.5	2446.4	2445.1	2437.3
	JUN 30 ECC, FT [7].....................................		2443.0	2443.0	2445.5	2446.4	2445.1	2437.3
	BASE ECC, FT	2452.6						
	LOWER LIMIT, FT	2287.0						
	JUL 31 ECC, FT		2459.0	2459.0	2459.0	2459.0	2459.0	2459.0
	JAN 1 - JUL 31 FORECAST, EARLYBIRD, MAF [8]...........		105.0	108.0	110.0	117.0	120.0	120.0

1/ LINE 1 - LINE 2 - LINE 3.
2/ PRECEDING LINE TIMES LINE 4.
3/ BASED ON POWER DISCHARGE REQUIREMENTS, DETERMINED FROM [8].
4/ CUMULATIVE MINIMUM OUTFLOW FROM [3], FROM DATE TO JULY.
5/ FULL CONTENT (2510.5 KSFD) PLUS [4], AND MINUS [2].
6/ ELEV. FROM [5], STORAGE CONTENT TABLE, DATED JUNE 1980.
7/ ELEV. FROM [6], BUT LIMITED BASE ECC, & ECC LOWER LIMIT.
8/ USED TO CALCULATE THE POWER DISCHARGE REQUIREMENTS FOR [3].

Table 6
Computation of Initial Controlled Flow
Columbia River at The Dalles
1 May 1984

1 May Forecast of May-August Unregulated Runoff Volume, MAF		74.0
Less Estimated Depletions, MAF		1.5
Less Upstream Storage Corrections, MAF		
MICA	7.9	
ARROW	4.8	
LIBBY	3.1	
DUNCAN	1.2	
HUNGRY HORSE	1.2	
FLATHEAD LAKE	.5	
NOXON	.0	
PEND OREILLE LAKE	.5	
GRAND COULEE	2.6	
BROWNLEE	.2	
DWORSHAK	.7	
JOHN DAY	.2	
TOTAL	24.4	24.4
Forecast of Adjusted Residual Runoff Volume, MAF		49.6
Computed initial Controlled Flow From Chart 1 of Flood Control Operating Plan, KCFS		315.0

Chart 1
Seasonal Precipitation
Columbia River Basin
October 1983 - March 1984
Percent of 1963-1977 Average

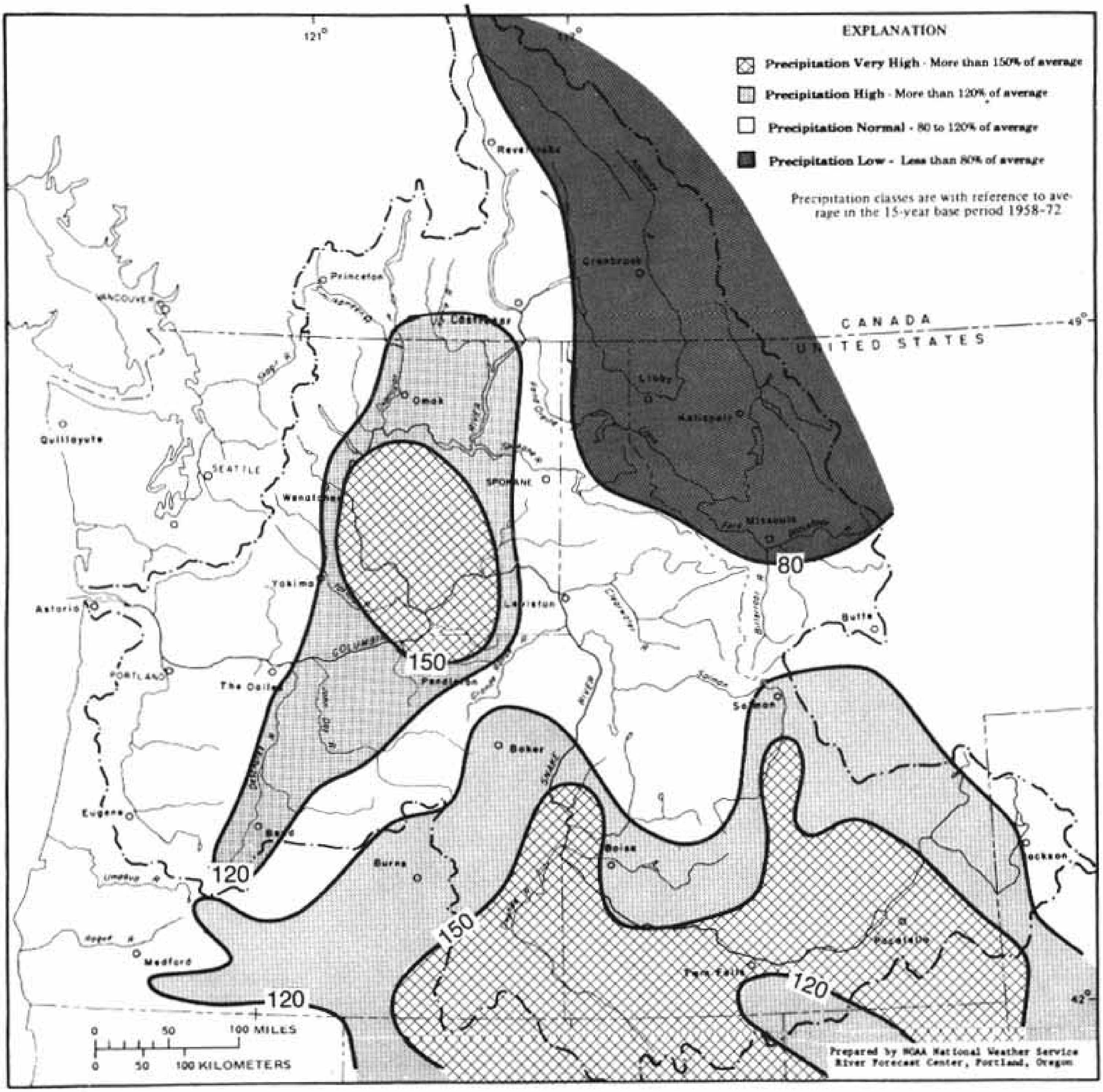
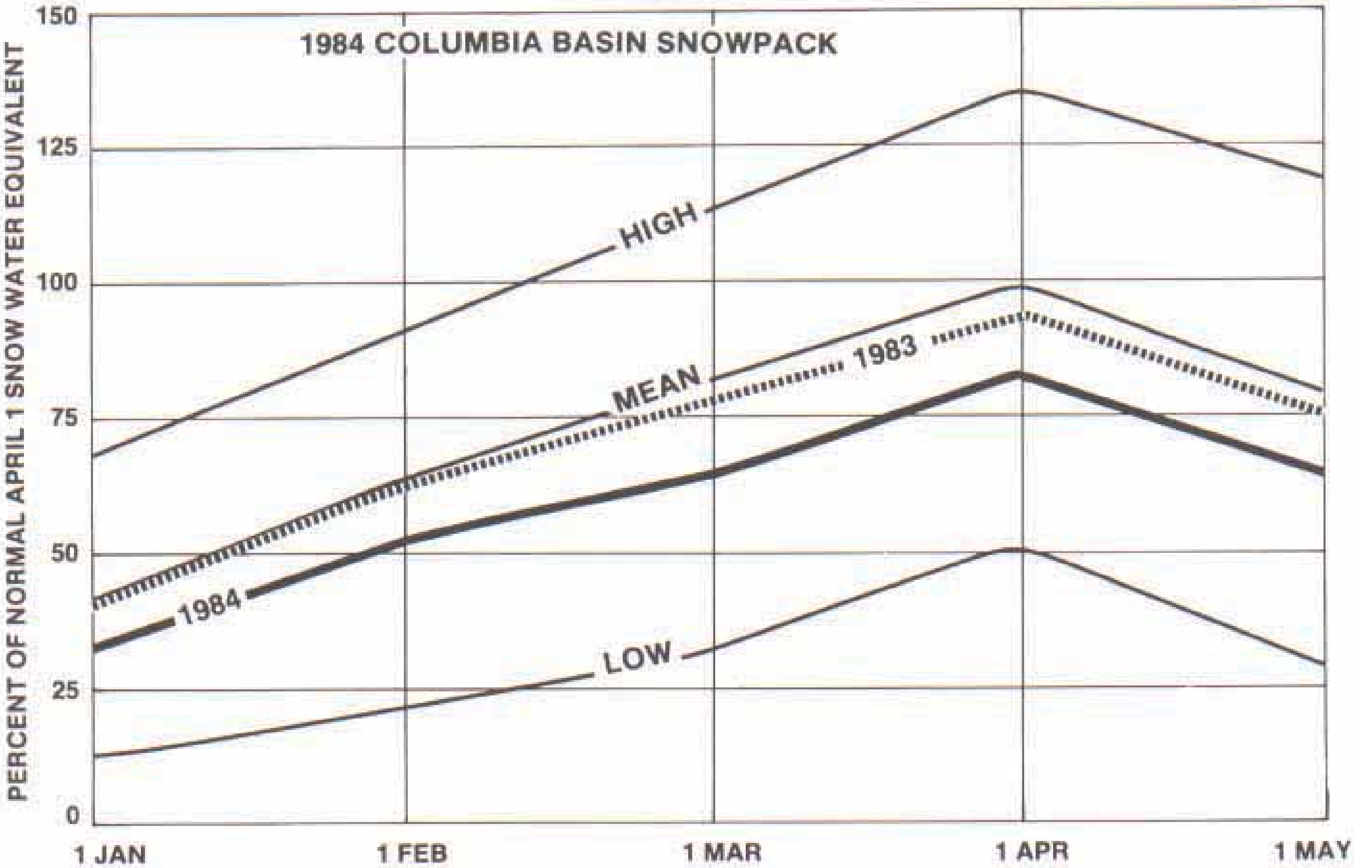


Chart 2
Winter Season
Temperature and Precipitation Indexes 1983-84
Columbia River Basin above The Dalles



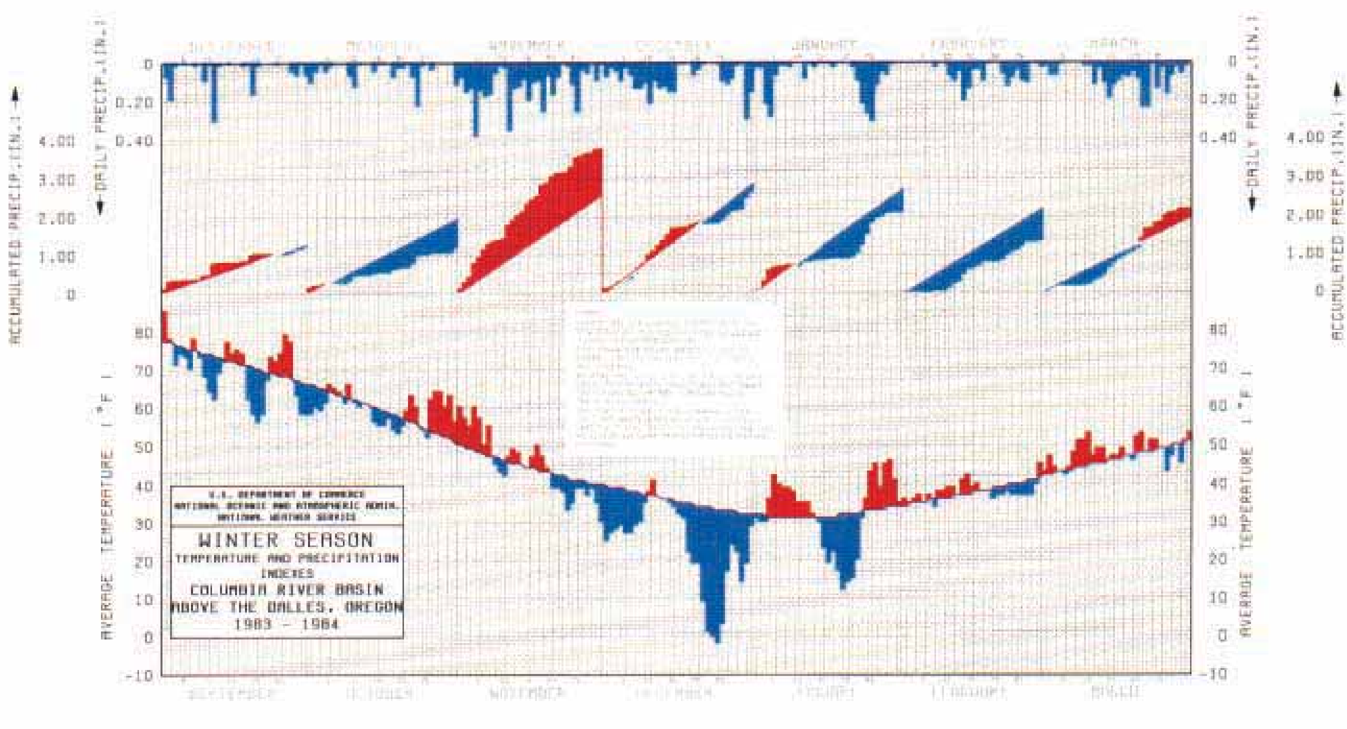


Chart 3
Snowmelt Season
Temperature and Precipitation Indexes 1983-84
Columbia River Basin above The Dalles

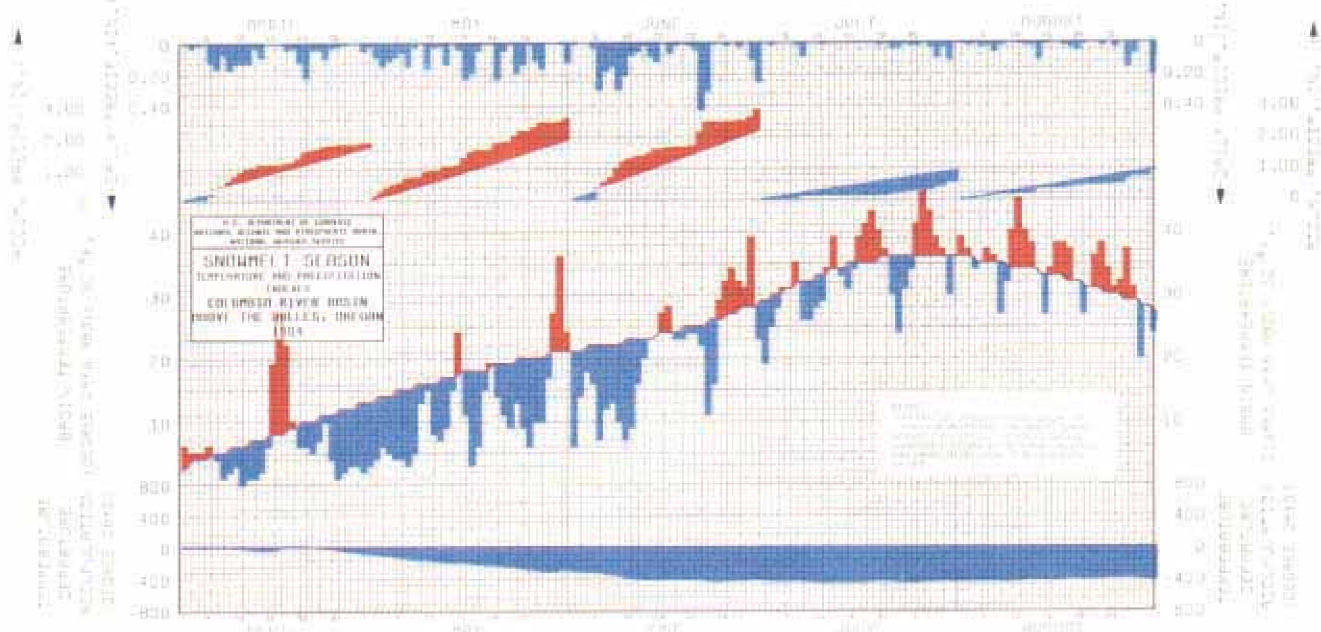


Chart 4
Snowmelt Season
Temperature and Precipitation Indexes 1983-84
Columbia River Basin in Canada

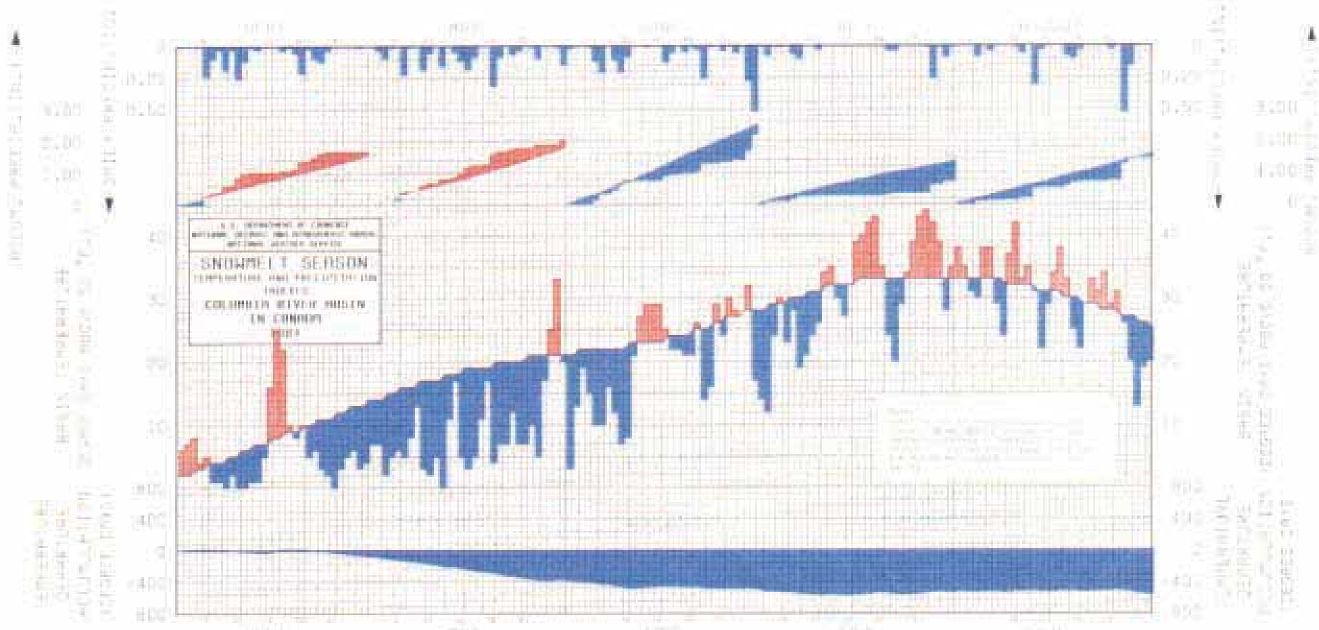


Chart 5
Regulation of Mica
1 Jul 1983 - 31 Jul 1984

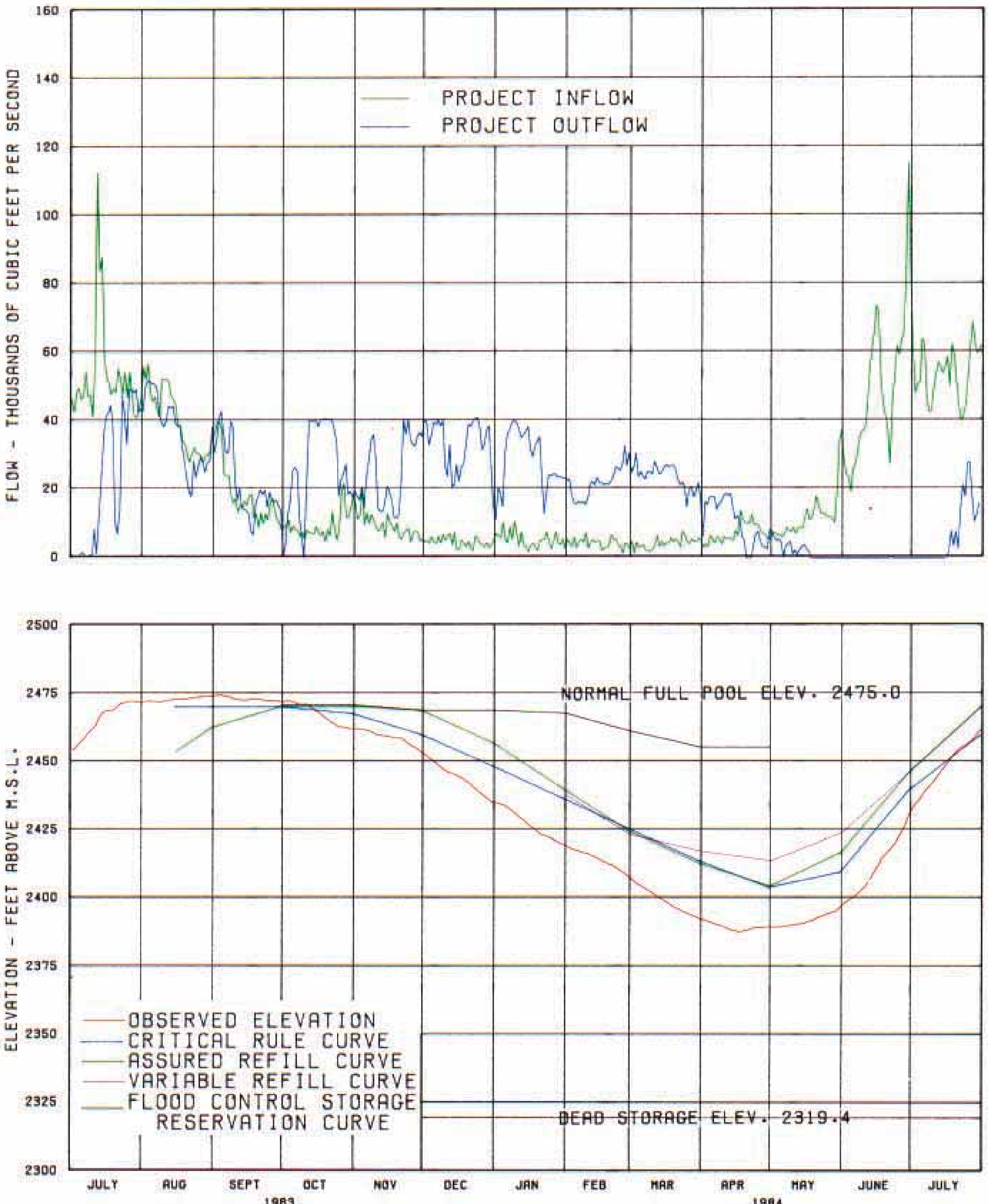


Chart 6
Regulation of Arrow
1 Jul 1983 - 31 Jul 1984

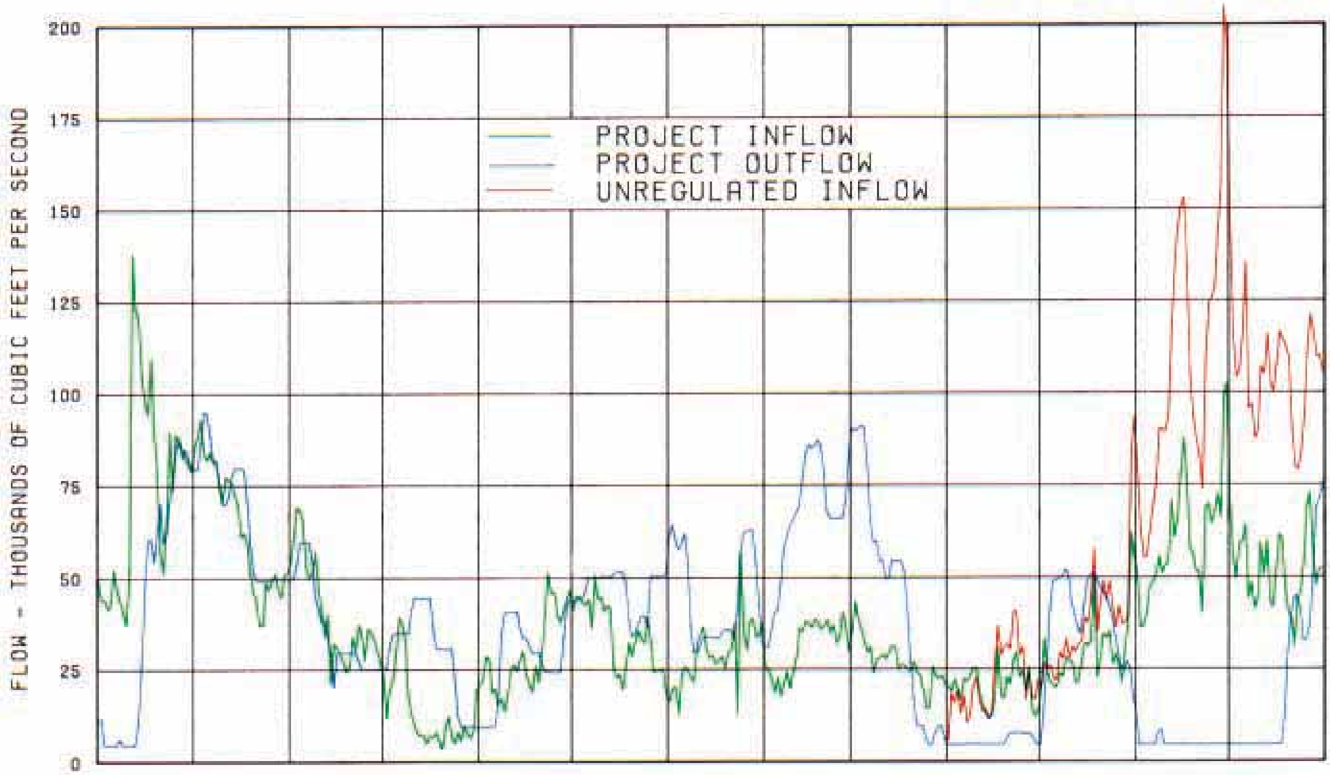


Chart 7
Regulation of Duncan
1 Jul 1983 - 31 Jul 1984

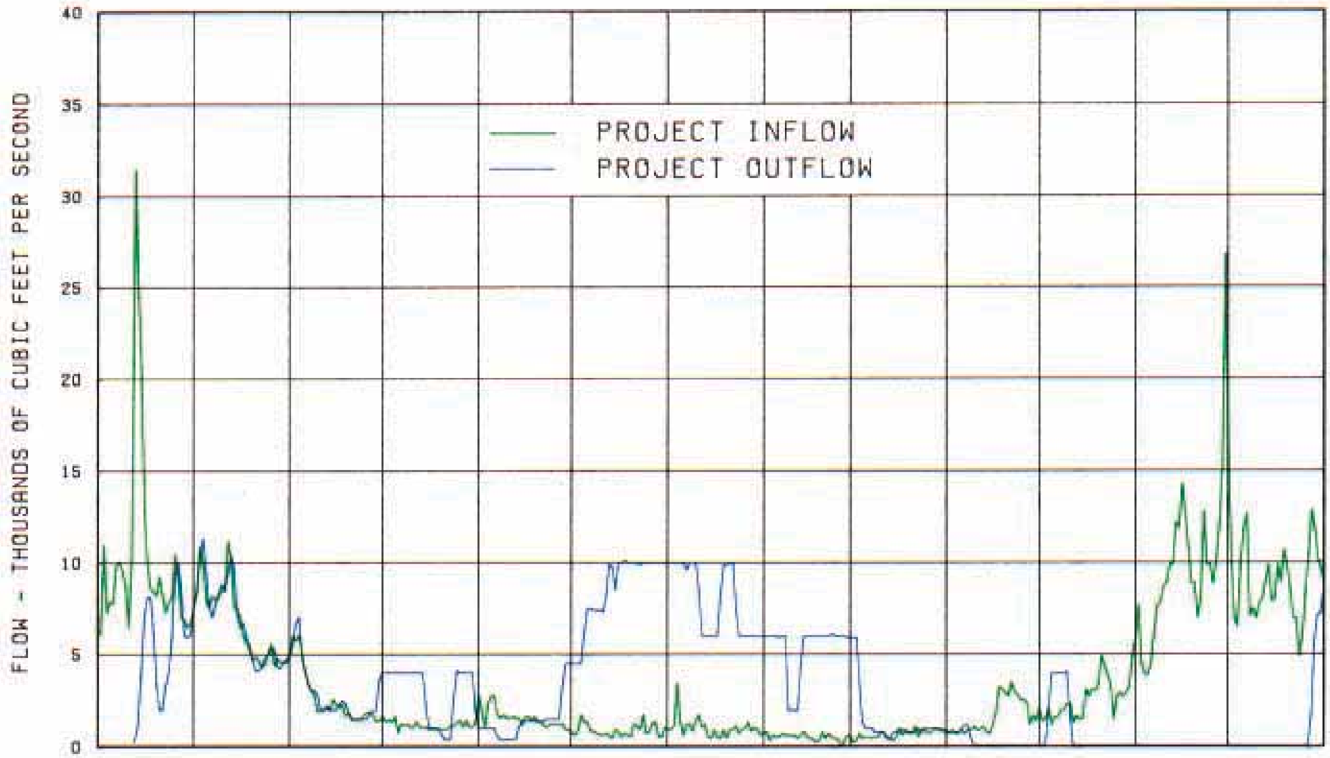
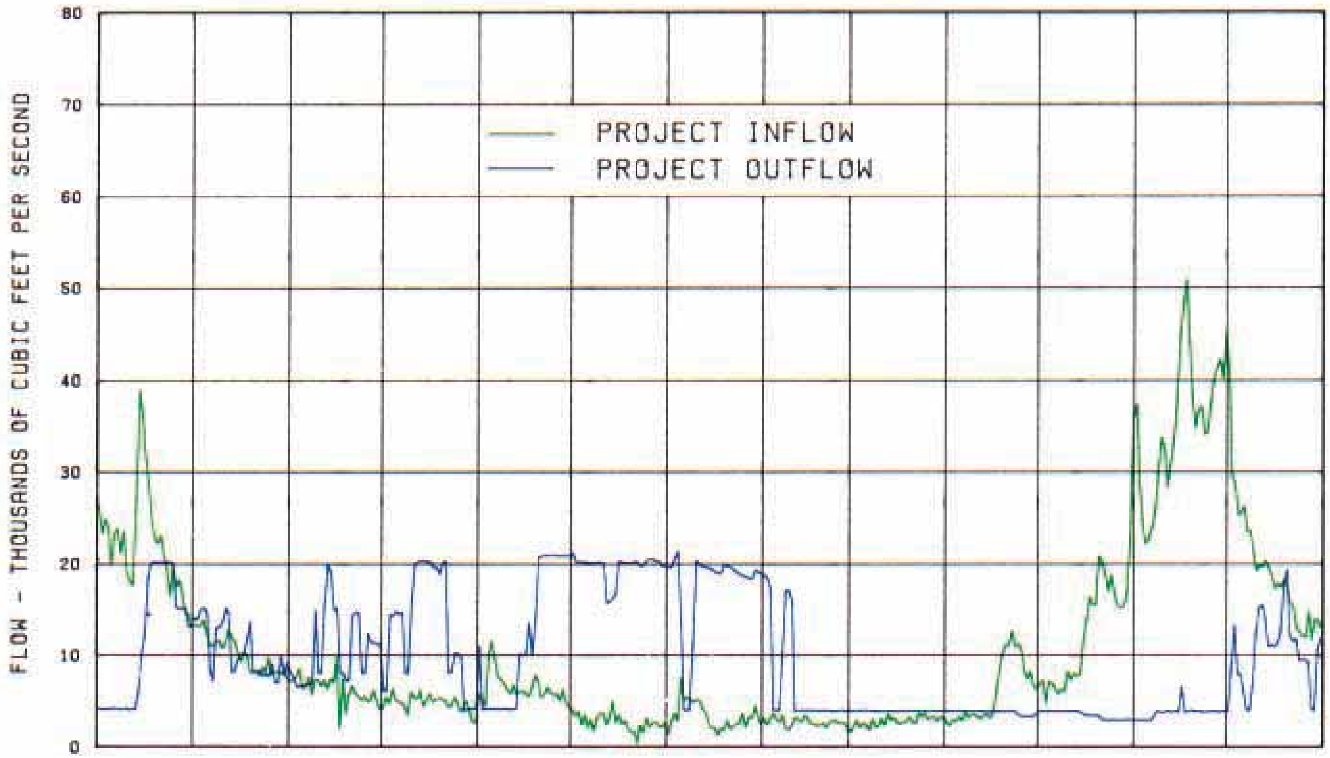


Chart 8
Regulation of Libby
1 Jul 1983 - 31 Jul 1984



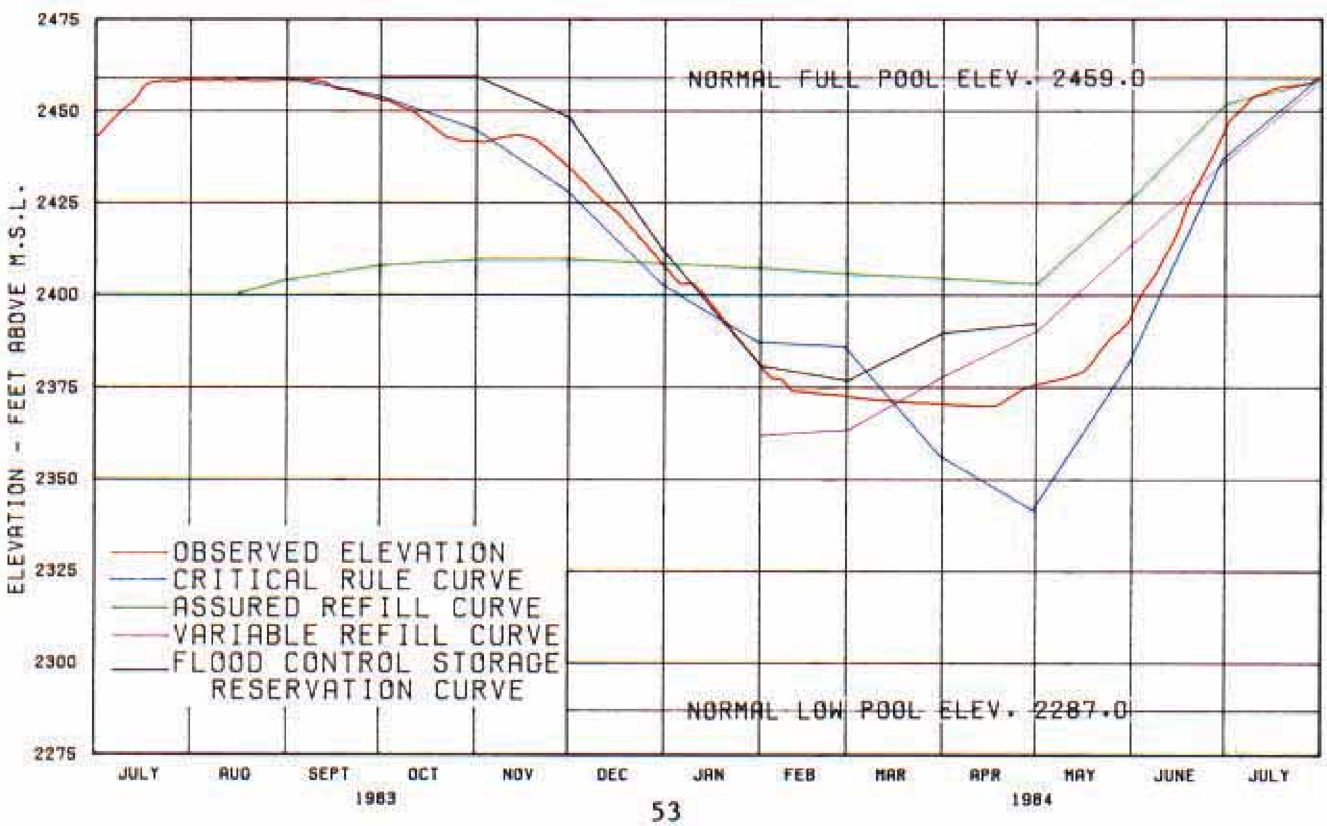


Chart 9
Regulation of Kootenay Lake
1 July 83 - 31 July 84

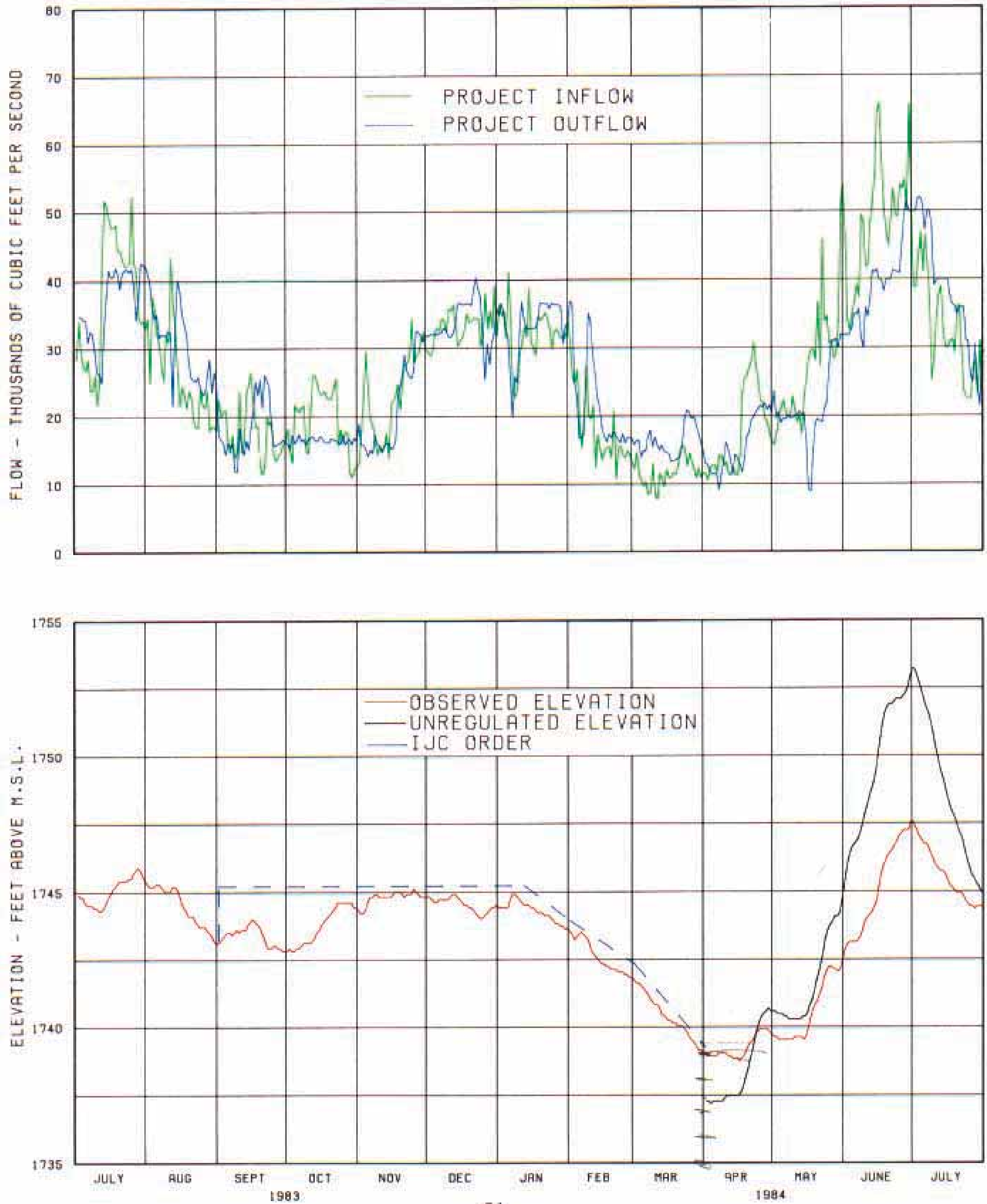


Chart 10
Columbia River at Birchbank
1 Jul 1983 - 31 Jul 1984

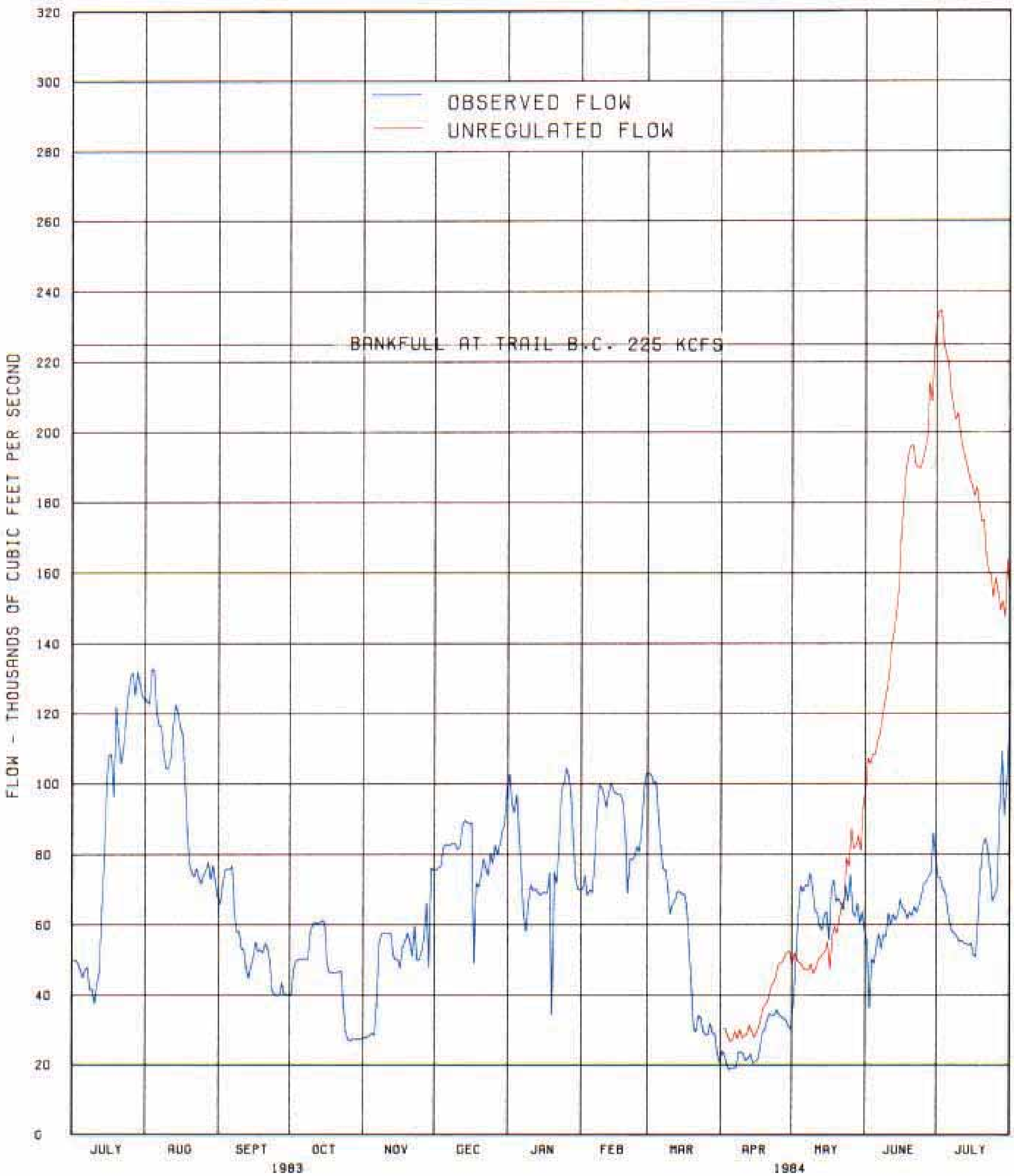
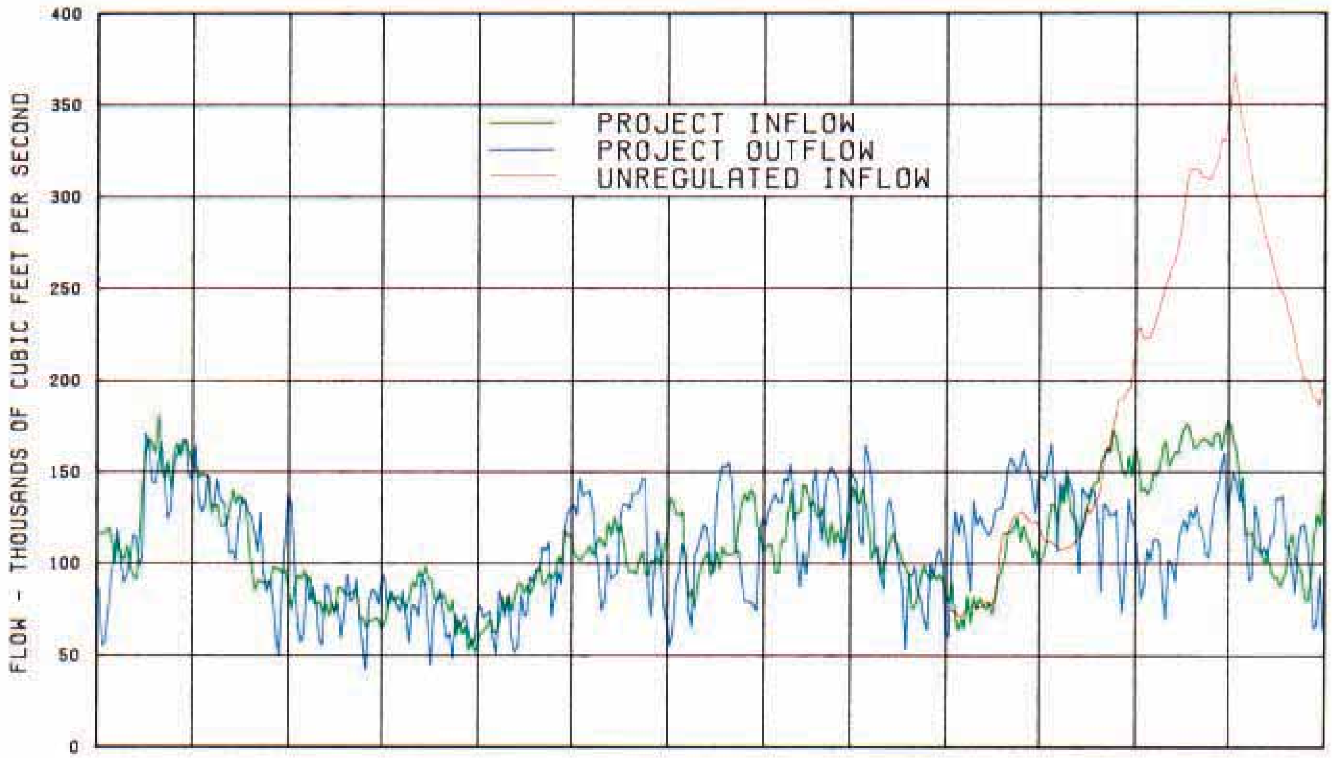


Chart 11
Regulation of Grand Coulee
1 Jul 1983 - 31 Jul 1984



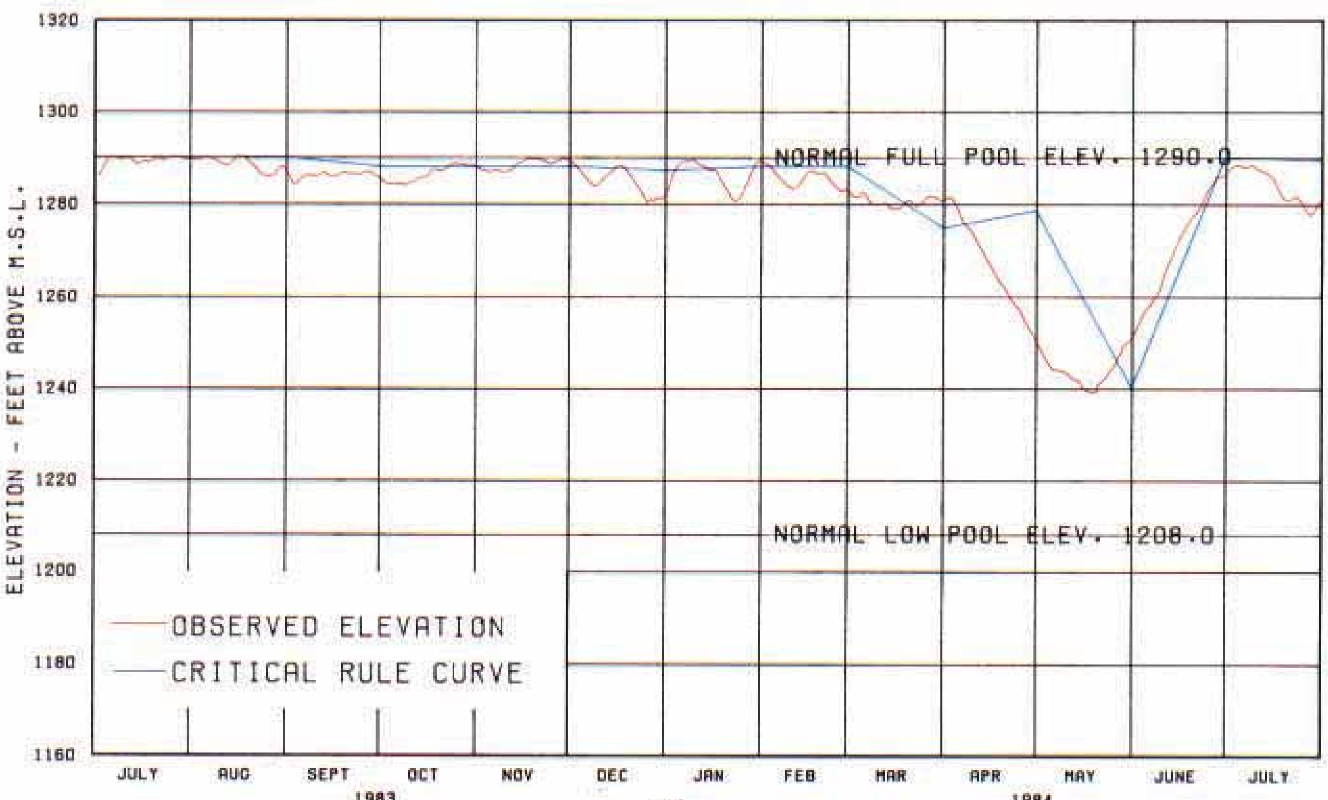


Chart 12
Columbia River at The Dalles
1 Jul 1983 - 31 Jul 1984

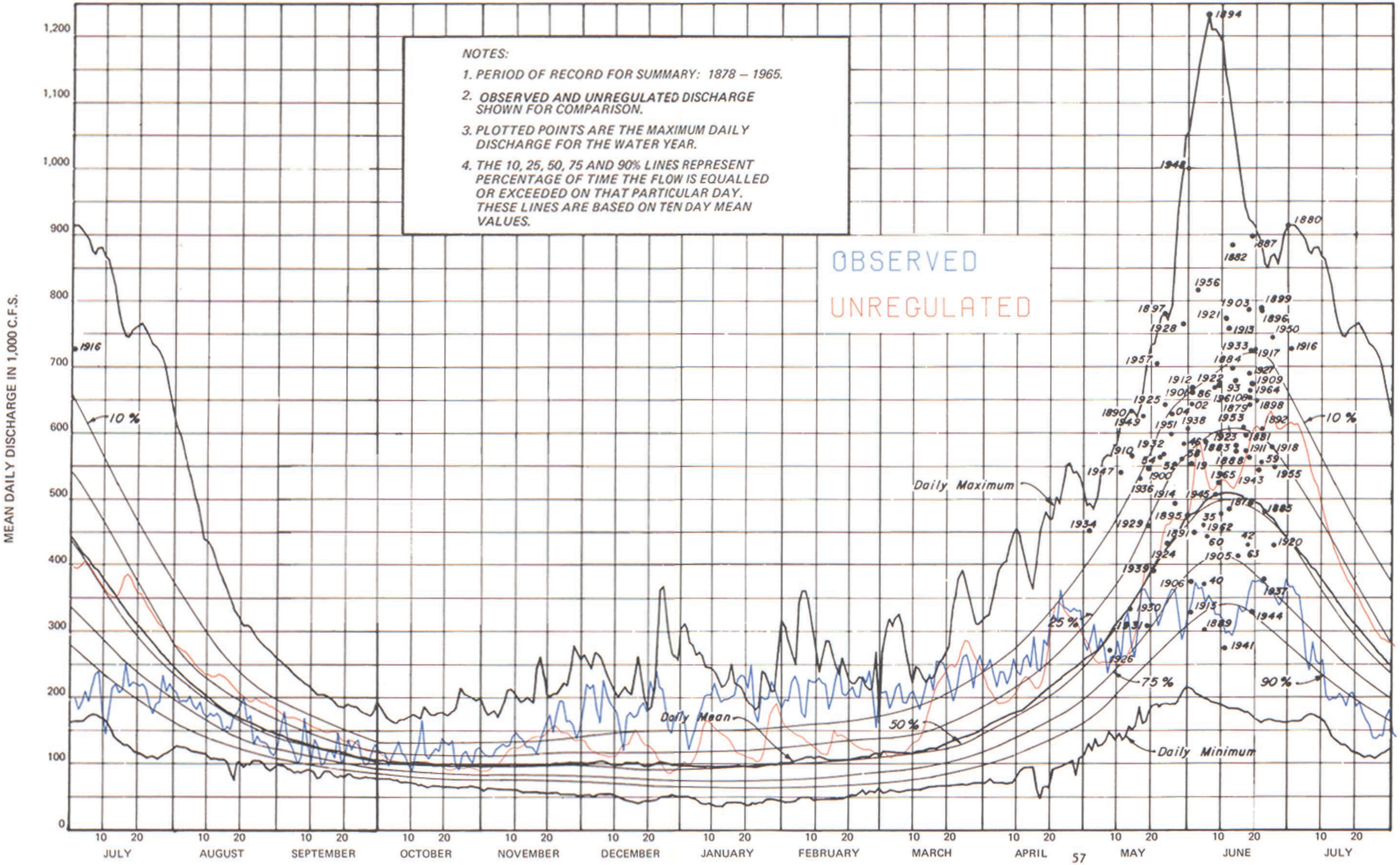


Chart 13
Columbia River at The Dalles
1 April 1984 - 31 July 1984

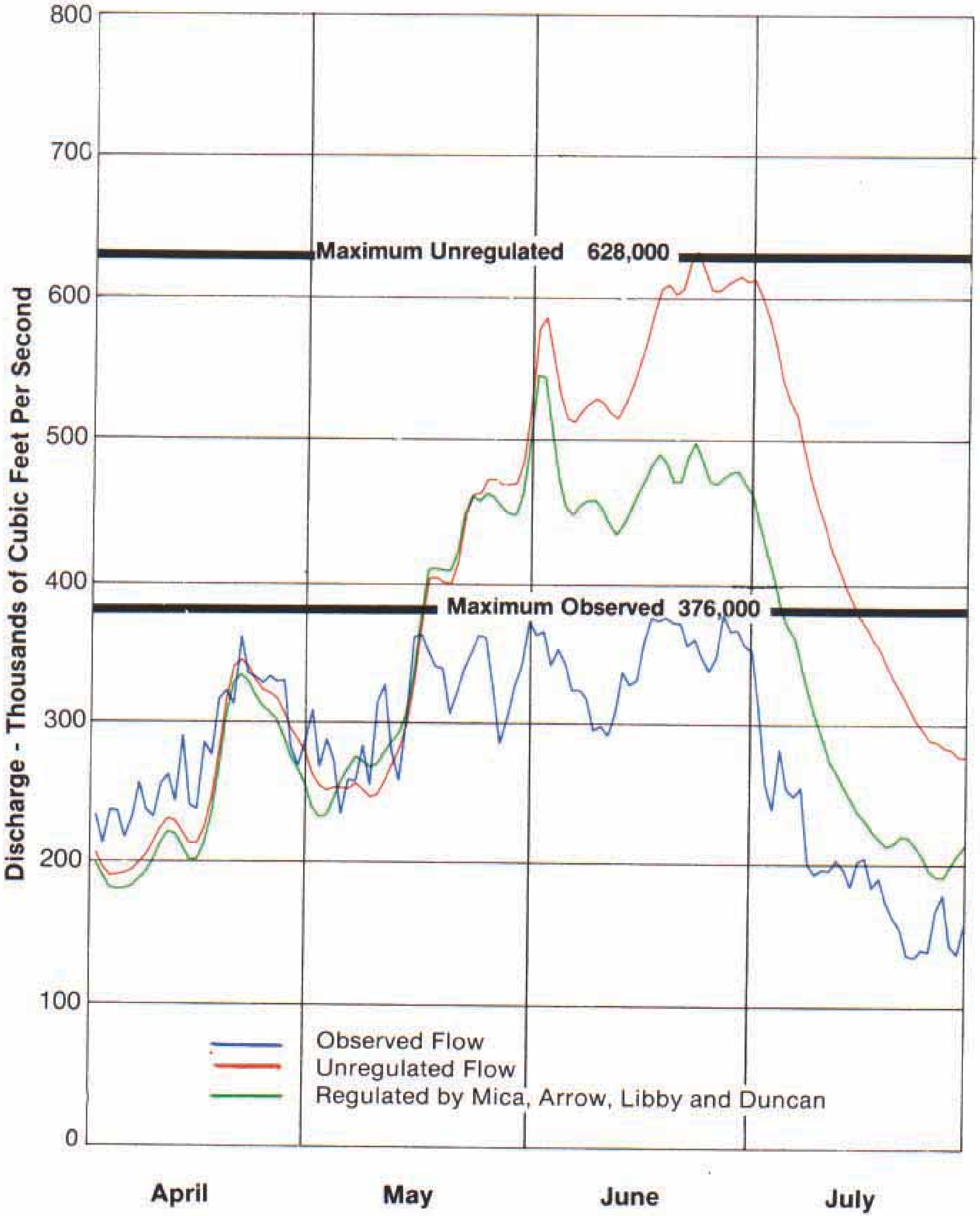


Chart 14
1984 Relative Filling
Arrow and Grand Coulee